BEFORE THE ARIZONA CORPORATION COMMISSION

LEA MARQUEZ PETERSON
CHAIRMAN
SANDRA KENNEDY
COMMISSIONER
JUSTIN OLSON
COMMISSIONER
ANNA TOVAR
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JIM O'CONNOR
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONALBE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-19-0236

RUCO'S CLOSING BRIEF

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing its Closing Brief in the above-referenced matter.

INTRODUCTION

On January 9, 2019, the Commission directed Staff to initiate a rate review of APS' then current rate rates to determine whether APS was over-earning[1]. The Commission's directive was in part based on trepidation regarding the Company's earnings since its August 2017 decision where it approved a net base rate increase of $94.62 million. RUCO-14 at 2. The

[1] References are made to the transcript page number or the Exhibit Number in the transcript. RUCO-14 at 1.

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result of Staff's efforts was the Overland Report, which was filed on June 4, 2019, and found, among many other things, that APS had $6.7 million of gross margin in 2018 that was associated with higher-than-expected revenues. RUCO-13 at 42. The Overland Report also delved deeply into the rate design issues that resulted from the transition to the "modernized rate plans" because of significant customer dissatisfaction regarding rate increase notices, customer lack of understanding of the modernized rate designs and concerns about being placed on demand rates. RUCO-13 at 2. The Report confirmed failures in the effectiveness of the CEOP. Id. at 28-29. The subsequent Staff commissioned "independent" report, the "Alexander report", filed on May 19, 2020, detailed the shortcomings of APS' CEOP. RUCO-14. Moreover, the Company's rate comparison tool was defective. RUCO-6 at 4. The Company's mishaps regarding its customer outreach caused one Commissioner to state "[r]atepayers should not shoulder the cost for a company's management failures, Companies will be held accountable for their poor business decisions. In this case, the Commission should also discuss whether financial disincentives are appropriate and what remedies are available to make ratepayers whole." RUCO-6 at 8. Chairman Marquez Peterson said in the December Open Meeting concerning APS customer service efforts: "For APS, these miscues seem to be the status quo and compounded by more bad news the next day." RUCO-6 at 4.

Not surprisingly, customer dissatisfaction has led to a feeling of mistrust of the Company. RUCO-6 at 5. Ratepayers feel that they are being overcharged. Id. Based primarily on the customer complaints and reports, the Commission directed APS to file this rate case in the hope, (from what RUCO believes), to address the complaints and restore some much-needed trust in the state's largest utility and the Commission itself. RUCO-14 at 1-11.

RUCO's review of the Company's application, together with other facts and analyses, confirms that ratepayers are being overcharged. RUCO's recommended base rate increase, after reflecting the Company's updated position on rebuttal and exclusive of adjustor transfers is ($61.4 million) or 1.87% decrease. See RUCO Final Schedules - Schedule A-1, page 1. Staff is recommending a base rate increase, exclusive of adjustor transfers of $59.808 or 1.82% increase. S-15, Schedule A, Attachment RCS-9, page 2 of 63. The Company in its rebuttal testimony updated its original rate increase of $184 million downward and is now recommending a base rate increase, exclusive of adjustor transfers of $168.824 million or 5.15%.

Barbara Lockwood, the Vice President of Regulation at APS testified that the Company "aggressively looked for ways to reduce the amount of the request and mitigate the impact on the customers bill." APS-1 at 9. There is sparse evidence to support this assertion. The evidence in the record indicates otherwise. This Brief will demonstrate otherwise. However, nothing can be as damning, given the facts that led up to this case and the reason for this case as explained above, that APS requested a yearly revenue increase of $168.824 million.

The fact is undisputed that neither the Company's revenue request nor Staff's will achieve the goal of a "rate decrease" in this case as requested by Chairman Marquez-Peterson in her letter in this docket of November 17, 2020. Neither the Company nor Staff's recommendations will reduce the average retail rate towards the $.09/kWh goal as specifically sought by Chairman Marquez-Peterson - the effect of the Company and Staff's recommendation will be just the opposite. The result will be higher rates which will further erode the confidence and trust of the public. A rate increase is not warranted at this time based on RUCO's analysis.

APS' Cost of Capital ("COC") Recommendation is an aggressive attempt to increase APS' rates. Staff's COC recommendation is also too high.

RUCO does not reach this conclusion lightly. The facts are that the Company's current ROE is 10%. Since its last rate case, and focusing mostly on the last year, the economy has been in a downfall, primarily due to a worldwide pandemic. Every financial indicator used in Cost of Capital modeling, including interest rates, treasury bond yields, etc. have been trending downward. See RUCO-4. The Company's witness, Ms. Bulkley's own exhibit shows that since the second half of 2014 the average quarterly ROEs for electric utilities in the United States has never been over 10% and has only been as high as 10 percent in one quarter (third quarter 2017). APS-20, Attachment AEB-6RB, S-3 at 2-3. Staff's Cost of Capital witness concluded that "Clearly it is Ms. Bulkley who is "out of tune" with the cost of capital for electric utilities throughout the United States. S-3 at 3. That conclusion can also be easily applied to Ms. Bulkley's Arizona specific knowledge - recently the Commission awarded a 9.10% percent in the Southwest Gas rate case (See Decision No. 77850 at 75, docketed December 17, 2020) and a 9.15% ROE in the TEP rate case. See Decision No. 77856 at 70, docketed December 31, 2020.

Staff's ROE recommendation of 9.4%, while certainly more "in tune" than the Company's recommendation is also too high. In its Direct case, filed on October 2, 2020, Mr. Parcel's ROE recommendation is "based upon his application" of four ROE models. S-1, page 1 of Executive Summary. Those models, and their ranges are as follows.

Model	Range	Midpoint
DCF	8.7 - 9.3%	9.0%
CAPM	6.4 - 6.6%	6.5%
Comparable Earnings (CE)	9.0-10%	9.5%
Risk Premium	8.3-9.1%	8.7%

Id.

Staff filed its Surrebuttal testimony on December 4, 2020 - roughly 2 months after its Direct. Staff's Surrebuttal ROE recommendation did not change. Not surprisingly, its updated COC analysis did not change much either. Mr. Parcells explains the changes:

> "The differences in the ROE model results can be summarized as follows:
>
> | | |
> |---|---|
> | DCF | 0.0% |
> | CAPM | 0.0% |
> | CE | -0.3% |
> | RP | -+0.2% |
> | Average | 1.0% |
>
> Collectively, these updated results indicate no change in the ROE of APS. My ROE recommendation for APS thus remains 9.4 percent."

S-3 at 13.

Staff's 9.4% ROE recommendation is higher than the very upper end of its DCF, CAPM and Risk Premium analysis. The only COC model that Staff's recommendation is in is its Comparable Earnings model. However, regarding its Comparable Earnings model, Staff's proxy group had an "updated" average value for 2020 ROE of 8.9% and for 2021 of 9.3%. S-4, Exhibit DCP-2 at Schedule 14.

Mr. Parcell notes that neither the courts nor economic/financial theory has developed exact and mechanical procedures for precisely determining the COC because COC is an opportunity cost and is prospective looking which means it must be estimated. S-1 at 7. Mr. Parcel then goes into detail in his Direct testimony about the current economy and the significant downward trends to the economic variables used by the experts to estimate COC. For example, Mr. Parcell explains how short-term and long-term interest rates rose sharply to record highs from 1972-1982 but have declined since due to declines in inflation. S-1 at 12. Since the COVID-19 pandemic began over one year ago long and short-term interest rates have continued to decline and remain at historic lows. Id. at 13. Investors' expectations have declined even with an uptick in stock prices because of 1) lower interest rates on bank deposits, 2) lower interest rate on US Treasury and utility bonds, 3) lower ROEs authorized by regulatory commissions, and 4) current shutdowns of many businesses in response to the pandemic are resulting in lower profit levels, equity returns and interest rates. S-1 at 15.

Mr. Parcell's testimony regarding the present economy is consistent with the testimony of RUCO's witness, John Cassidy. Given the understanding that ROE is an estimate, we are in the middle of a pandemic, and financial indicators are at record lows it is simply illogical to award an ROE that is beyond the high range of three-quarters of the models used in Staff's COC analysis. Staff's ROE recommendation is too high and should be rejected. Further support for RUCO's 8.70% recommended ROE was provided by Mr. Cassidy at hearing, pointing out that Value Line projects the common equity ratio of APS' holding company parent, Pinnacle West Corporation to fall to 43.0%, a 990-basis point decline over the period, 2019-2024. Transcript at 4321, 4323.

Both APS and Staff seek approval of an additional return on the Fair Value Increment (FVI). APS seeks approval of a FYI cost rate of 0.80%. APS-21 at 69. Staff's first proposal is to incorporate a zero percent return on the FVRB. S-1 at. RUCO also recommends a zero percent return on the FVI. RUCO-5 at 13. In the alternative, Staff recommends a 0.3 percent return on the FVI. Id. at 53.

APS describes its request as "conservative" compared to the real risk-free rate of 1.28%. Id. APS' comparison is also "out of tune" given its request. In the TEP decision, the Commission concluded "We agree with RUCO's assertion that the FVI represents non-investor supplied capital and the application of a return on an FVI provides utilities with a premium return above the nominal ROE applied to rate base." Decision No. 77856 at 69. The Commission further concluded:

> Although we agree with RUCO that it is not necessary to provide the Company with any additional return on the increment between the OCRB and FVRB because that increment is not financed with investor-supplied funds, we find that applying a return on the FVI is appropriate under the specific facts and circumstances of this case. We further find that applying a 0.20 percent real risk-free rate to the FVI complies with the Commission's constitutional fair value requirement, is an appropriate methodology to determine the fair value rate of return without overstating the effects of inflation, and will result in just and reasonable rates. In addition, we find that the application of a return on the FVI reduces risk to the Company because that return provides TEP with an additional source of income and cash flow. Accordingly, we find that it is reasonable and appropriate under the circumstances to adjust the Company's ROE downward by 20 basis points to reflect that reduced risk to TEP.

Decision No. 77856 at 69-70.

In Southwest Gas, the Commission concluded:

> Although we agree with Arizona Grain, RUCO, and Staff that it is not necessary to provide the Company with any additional return on the increment between OCRB and FVRB because that increment is not financed with investor-supplied funds represented on its balance sheet, we find that applying a return on the FVI is appropriate under the specific facts and circumstances of this case. We further find that applying a 0.18 percent real risk-free rate to the FVI complies with the Commission's constitutional fair value requirement, is an appropriate methodology to determine the fair value rate of return without overstating the effects of inflation, and will result in just and reasonable rates. In addition, we find that the application of a return on the FVI reduces risk to the Company because that return provides SWG with an additional source of income and cash flow. Accordingly, we find that it is reasonable and appropriate under the circumstances to adjust the Company's COE downward by 20 basis points to reflect that reduced risk to SWG.

Decision No. 77850 at 74.

At hearing, Staff's witness Mr. Parcell was asked:

> "...What benefit does the ratepayer get from applying any return above zero to the fair value increment?
>
> A. The benefit of higher rates"

Transcript at 4965. Mr. Parcell said that he should not have said that but then said, "It adds -- it makes rates higher, and service is no better." Id. Mr. Parcel explains that once the COC is determined, it is then applied to the ratebase which is derived from the asset side of the balance sheet. S-1 at 48. From a financial perspective, this rationale for this relationship is that the ratebase is financed by the capitalization. Id. For the relationship to have any meaning, the COC should be applied to the OCRB because there is a matching of the ratebase and capitalization. Id. The link is broken, however when the FVRB is used because the amount the FVRB exceeds the OCRB is not financed by investor supplied capital. Id. at 49.

Staff's explanation explains why neither APS nor Staff's alternative recommendation should be approved. What really is at issue is how much of a gift the Commission should award here. Is the Company's .08% request really an attempt on its part to aggressively reduce the amount of its request in this case? Hardly, it is just the opposite - it is an aggressive attempt to increase the request without a sound financial or other basis. Neither APS nor Staff or the Commission in the past has explained or even offered a policy reason for the extra return. Indeed, Staff's witness said the only benefit of it is to raise the ratepayer's rates! Regardless, the *Chaparral* cases[2] which were appealed and decided by the Court of Appeals in several Memorandum Decisions seem to be the basis for the legal argument that the State's constitutional fair value requirement requires the Commission award a return on the

[2] Decision Nos. 68176 and 70441.

FVI[3]. S-1 at 47. RUCO would point out that the Court of Appeals Decisions regarding Chaparral were Memorandum Decisions and do not create legal precedent nor can be cited as precedent. See Arizona Rules of the Supreme Court 111(C).

Chaparral dealt with a methodology used by the Commission which backed into an operating income. See Decision No. 70441 at 4-5. The Court of Appeals did not define fair value. RUCO understands the argument that the return has ties to fair value, as it parallels the arguments RUCO made in the far more recent Arizona Supreme Court case of *RUCO v. ACC, 240 AZ 108, 377 P. 3d 305 (2016)*. The Supreme Court in its Opinion in *RUCO*, which *is* precedential, rejected RUCO's arguments inferring that there is a relationship between return and fair value, concluding that "fair value" applies "…only to the "rate base" element of the traditional ratemaking equation," and not the rate of return. *Id.* at 240 AZ 108,112 (pp. 14).

RUCO v. ACC addresses the issue before the Commission squarely, not *Chaparral. Chaparral* dealt with *a* methodology that backed into an operating income that gave no weight to the FVRB. In the present case, the return in question is being applied to the FVRB – that is undisputed. There is no attempt in this case to reach a desired operating income. The legal argument requiring a return on the FVI assumes that the Commission's discretion to determine Cost of Capital is limited since any aspect of the traditional regulatory formula can be manipulated to arrive at a desired revenue requirement. Whereas, in *RUCO v. ACC* the issue of whether Fair Value requires analysis beyond the ratebase was before the Court and the Court concluded otherwise. *Supra* at 240 AZ 108,112 (pp. 14).

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[3] 1-CA-CC05-002, Memorandum Decision dated February 13, 2007, 1-CA-CC 08-002, Memorandum Decision dated June 10, 2010. https://www.azcourts.gov/Portals/0/OpinionFiles/Div1/2010/1%20CA-CC%2008-0002-120942.pdf. RUCO is not citing either Memorandum Decision as precedent - only to explain procedurally what happened in the *Chaparral* matters referenced in Mr. Parcel and other testimonies.

Fair value is not something that can be argued when it is convenient. *RUCO v. ACC* is dispositive of the argument that the Commission must award a positive return on the fair value increment ("FVI"). When it comes to fair value, one has nothing to do with the other as the Supreme Court ruled. It is the ***return*** that is in question, not the ratebase. In *RUCO v. ACC,* the Company, with the help of numerous utilities argued that the return, among other things, is not a factor in fair value otherwise the System Improvement Benefit mechanism ("SIB") would not have survived legal challenge, as was determined by the Court of Appeals. Now, the Company wants to pigeon-hole the Commission based on a broad interpretation of fair value to earn a return on what is, non-investor supplied capital. Such a result is not only inappropriate it is unfair to the ratepayer.

There is no basis from a financial perspective to award a return on the FVI. S-1 at 49-50. That does not mean, however, that the Commission cannot for policy reasons award a return on the fair value increment. The Commission recently awarded a zero return on the FVI in an AWC rate case – Decision No. 77380 (2019) at 36-37.

While RUCO would prefer the Commission award no return on the FVI, RUCO is aware that legal concerns have been raised. For example see S-1 at 51. RUCO would not object should the Commission award a return on the FVI if accompanied by a corresponding adjustment to the ROE resulting from the additional source of revenue. RUCO notes that the Commission has addressed the matter in this manner in the recent SWG and TEP cases mentioned above. RUCO also notes that on remand in the *Chaparral* case, the Commission reduced the Company's ROE from 9.3% to 7.3% to eliminate the "inflation factor." See Decision No. 70441 at 37. Chaparral unsuccessfully appealed the Commission's remand decision.

RUCO recommends that the Commission adopt its ROE of 8.70%. RUCO-5 at 2. RUCO's weighted cost of common equity is 8.90%. Id. RUCO reduced the weighted cost by 20 basis points for the customer service issues described above. RUCO's 8.90% weighted cost was determined by assigning a 40.00 percent weight to estimates obtained from the DCF and CE models, and a 20.00 percent weight to estimates obtained from the CAPM. RUCO-5 at 3. RUCO's 8.90% weighted cost is in the high end of its DCF analysis, is 110 basis points higher than its top CAPM range and is 60 basis points lower than the bottom end of its Comparable Earnings range. RUCO-5 at 2. RUCO's ROE recommendation also is clearly within the range of results of Staff's modeling. RUCO's 8.90% weighted cost is a closer approximation of the average and midpoints of Staff's modeling than Staff's 9.40% ROE recommendation. See S-1, page 1 of Executive Summary.

Finally, of the three[4] COC recommendations, while RUCO's may be the lowest, it is the most in-line with perhaps the most important objective of this rate case - to help address the rate and other negative impacts to the ratepayer caused by the last rate case. RUCO did not approach this case seeking the lowest cost solution. RUCO approached this case truly focused on the rate impact while at the same time being fair to the Company. Yes, this case is and should be more about the ratepayer and not all about the Company's shareholders and investors. Why should the Commission in this case adopt an ROE that is beyond the highest range of three out of the four models used in the COC analysis as Staff recommends? How does that move rates towards the $.09kWh range Chairman Marquez-Peterson referenced in her correspondence of November 17, 2020?

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[4] RUCO, Staff and the Company

RUCO's COC recommendation is within the mid-range of Staff and RUCO's modeling. It is fair. It is also unlikely to financially harm the Company in any way or impair its ability to provide safe and reliable service. Transcript at 4333. The argument that ratepayers will be harmed financially by reducing the Company's profit is nonsense. The Commission should adopt RUCO's COC recommendation.

The Commission should reduce the ROE by 20 basis points in response to APS' inferior customer service.

There is no question that the Company's customer service has been wholly inadequate for a long time. The Company suffers from a corporate culture that is clearly out of tune with regard to what constitutes good customer service. Rather than embrace the obvious and work on it, this Company would rather spend its time, money and efforts commissioning reports and other means to support its misguided perception of superior customer service. As Chairman Marquez-Peterson summed up at Open Meeting in December, "For APS, these miscues seem to be the status quo and compounded by more bad news the next day." RUCO-6 at 3.

RUCO's analysis found, among other things, the following key factors identified as inadequate, and unacceptable customer service:

1. The Company failed to establish adequate measurements to determine if the CEOP plan they implemented was effective in educating customers regarding how to select a Rate plan best suited to the customers' needs.
2. The Company had inadequate and confusing customer contacts.[5]

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[5] "APS's CEOP should have included more personal customer contact or outreach efforts regarding the new modernized rate plans and which plan would be of most benefit to the customer." ...
"APS did not explain the adjuster mechanisms in its CEOP, nor did APS clarify the fact that there would be annual updates to the adjuster mechanism billing rates occurring outside of the rate case and that such rate

3. The Company's Rate Comparison Tool was defective.
4. The Company summarily rejected customer advocates' proposals and suggestions.
5. The nomenclature of the various rate plans was confusing to customers.
6. Actual customer bills were not easily understandable.[6]

RUCO-6 at 3-4. There are many sources identified in the record which establish the customer service flaws such as the Overland Report, the Alexander Report, etc. RUCO-13, and RUCO-15. The Commission in Decision No. 77280 also sets forth findings detailing the numerous problems - Overland Report. RUCO-13, Decision No. 77270 at 2-8.

The customer complaints are numerous and populate the Commission's dockets. Id. at 4-5. The level of customer dissatisfaction is significant and far beyond acceptable. Id. Perhaps this explains why JD Power's rankings for APS have been on the decrease with a 2019 ranking in the West Region tied for the last place among the thirteen west region utilities. Id. at 7. In response, the Company in 2017 transitioned from JD Powers to Customer Contact Tracker ("CCT"). APS-23 at 25. APS claims it did not switch to CCT to circumvent declining satisfaction results. Id. at 26. Even given the benefit of the doubt, JD Powers ratings continued

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changes may result in an increase in customer bills. These additional bill adjustments may have been confusing to some customers, especially without notice of the adjuster mechanism changes." ...
"The information provided by APS in its rate increase notices and personalized letters failed to convey certain important information, including:
The "average customer" rate increase percentage and bill impact (4.5% increase, $6 per month) disclosed in customer notices and press releases <u>failed to adequately convey that the impact of the modernized rate design on individual customers could vary widely, and over time, depending on customer-specific circumstances and changes in other customer bill components such as adjusters and taxes and fees, and were not included in the notice regarding the average percentage or bill increase.</u> The rate plan transition letters mailed in the first few months of 2018 failed to adequately convey to customers that the additional increases in their bills, beyond those that occurred with the 2017 transition rates. The information conveyed did not include that these additional increase in bills were dependent on customer-specific circumstances, including the specific rate plans customers were on before and after the transition, and behavioral changes in energy usage patterns under the new rate plans which could minimize bill increases, such as shifting usage to accommodate the new on-peak hours and demand charges." (emphasis added)
Overland Report P.5-7 filed June 4, 2019 http://docket.images.azcc.gov/0000198445.pdf

to go down while the customer complaints continued to rise consistent with the JD Powers metrics. RUCO-6 at 7, Decision No. 77270 at 2-8. APS's approach, to effectively try and take the eye off the ball, a major miscue, has only worsened the situation.

Another miscue was APS' response to the Alexander report. The Alexander report was commissioned by the Staff at the direction of the Commission in June 2019 to develop a program to properly educate customers. See RUCO-14, Decision No. 77270 at 8. The result was the Alexander Report which was a very detailed report which critiqued and exposed the problems with APS CEOP. RUCO-15. The Alexander Report also made many recommendations and fulfilled its purpose and objective. It was not flattering for the Company, but it thoroughly reviewed the CEOP and was independent. APS' response was to commission its own report at its own initiative to respond and critique the Alexander report. The result was the Guidehouse report which was dated November 2, 2020. The Company's approach here again is to spend the time, effort, and expense to critique the Commission's directed independent report with its own report which, like the justification for the abrupt change from JD Powers to CCT, purports that the Company is in a far more favorable position. As APS witness Whiting testified, among other things the "Guidehouse assessed the CEOP and compared it to industry norms, and they concluded that the CEOP met and, in some instances, exceeded industry norms." APS-23 at 19. APS then concludes that the "harsh rhetoric" surrounding the 2017 CEOP is not supported by the facts. Id. One fact, among the many which suggest that the "harsh rhetoric" has support in this record is the Consent

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[6] For a detailed description of APS customer bill's complexity, see: Customer comment articulating the challenges in understanding an APS bill written by Steve Neil and filed by Commissioner Olsen on December 19, 2019 in Docket No 19-00003 at https://docket.images.azcc.gov/E000004007.pdf

Agreement APS just entered into for $25 million with the Arizona Attorney General to settle CEOP issues.

To not belabor the overwhelming record in this case which supports some sort of meaningful accountability as Commissioner Dunn called for on this issue, RUCO would simply refer to the record in this case for additional support. The question of accountability is before this Commission and RUCO is the only party offering a recommendation. RUCO urges the Commission not to overlook what has happened and the serious inconvenience and hardship APS has caused its customers. RUCO submits that the Commission must take action to impress upon this Company that substandard service will not be tolerated especially that this Company's ratepayers are already paying a premium for electric service, as Chairman Marquez-Peterson so aptly points out in her November 17, 2020 letter.

The Commission's consideration of Cost of Capital is one place where action can be taken. As Mr. Parcell points out, the ROE is at best an estimate. There are many factors that can be considered, including Company performance. The Maine Public Utilities Commission recently adjusted a Company's ROE to address failing customer service metrics[7]. RUCO recommends the Commission reduce the Company's ROE by 20 basis points which RUCO estimates is commensurate to the annual harm ratepayers have received. RUCO-6 at 18.

The Commission should reject the Company's proposed Community Coal Transition Proposal ("CCT")

On November 5, 2020, APS and the Navajo Nation entered a Memorandum of Understanding ("MOU") to address the transition from coal-fired generation. APS-5 at 8, APS-

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[7] RUCO-6 at 15, See https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=105431&CaseNumber=2018-00194.

2, Attachment BDL-02RJ. APS' CCT is part of its Clean Energy Commitment. APS-5 at 8. APS's Clean Energy Commitment was announced in January 2020, and among other things APS pledged to end coal fired generation by 2031. Id. at 8, RUCO-10.

The MOU, which was signed the day before APS submitted its rebuttal case, incorporates the understanding between APS and the Navajo nation. APS-2, Attachment BDL-02RJ. APS is proposing a net total of $128.75 million of support to the Navajo nation. APS-2 at 21. Of that total, $23.75 million will be provided by the shareholders. Id. The CCT will involve a $100 million cash payment, paid at approximately $10 million per year over the next ten years, to the Navajo nation. APS-2 at 20. These funds will be collected through APS' proposed AEM adjustor. Id. Other features of the CCT will include additional electrification projects within the nation at a funding level of $10 million, with $5 million of that collected through the AEM and the other $5 million funded by shareholders. It should be noted that the Nation may be receiving other funding for such efforts, as proposed by the New Mexico Legislature. APS will also provide $2.5 million per year to the Navajo nation from shareholder funds from the time the Four Corners Power Plant closes through 2038. APS-5 at 28. APS is also proposing $3.7 million to be paid over five years with $3.35 million recovered through APS's proposed AEM and 0.35 million funded by shareholders. APS-2 at 23.

APS' CCT proposal raises far more questions than it answers and the disparity between the proposed ratepayer share and the shareholder's share suggests another aggressive attempt to burden the ratepayers with higher rates.

The CCT is not a necessary cost of service. Ratepayers will not see improved service or any change in service as the result of over $100 million in cost. At the very least, ratepayers should know exactly what they are getting for their money, why they will have to pay higher rates for the CCT, and an invitation to the discussions which lead to and result in "a fair and just transition." "Fair and just" means exactly that - a proposal that is fair and just to everyone involved, not just the two entities, APS, and the Navajo Nation, that are involved in the proposal.

The fact that the Hopi Tribe "rejects its treatment by APS in the proposed Transition Plan terms" is telling. Hopi-6 at 3. Chairman Nuvangyaoma testified that contrary to Mr. Guldner's assertions, the Hopi Tribe had not had any "discussions" with APS. Id. President Nez, the President of the Navajo tribe, testified that at the negotiations with the tribe, APS was there representing both the ratepayers and the shareholders. Transcript at 3486. President Nez is incorrect there was no representative present at the negotiations on behalf of the non-Navajo ratepayers. There were no ratepayer advocacy groups there. Id. There were no other affected communities outside of the tribe. There was no other state, county, city, federal, legislative, or other communities. APS allegedly "represented" them all and came to terms in the middle of the rate case.

President Nez, when asked whether this will be the total commitment that APS' ratepayers will be asked to make towards transition testified that it is a "great start." Transcript at 3330. It is unclear whether APS views this CCT as a start but certainly APS' ratepayers need to know the extent of their obligation - a question that remains uncertain.

In the recent TEP case, the Commission concluded:

> Further, because it is imperative that a solution be found to the Citizen Groups' concerns, and because of the exigency of the situation, we direct Staff to open the generic docket as soon as possible, but no later than January 17. 2021, and Staff shall begin soliciting comments from impacted communities. The Governor's Office, state legislature, regulated and unregulated entities, state and federal agencies, and public utility commissions in neighboring states regarding the generic docket, such that Staff can make recommendations to the Commission by May 29, 2021.

Decision No. 77856 at 172.

It is logical that such an important decision, with so much money at stake on what amounts to a policy call - i.e. not necessary for cost of service, be vetted in its entirety. A vehicle, the generic docket, has been made available by the Commission which will give it the necessary information to make an informed decision.

RUCO does not object to a discussion on a fair transition - just the opposite - RUCO welcomes the discussion. RUCO does object to a one-off proposal such as what APS is making here, that was poorly represented, lacked sufficient stakeholder involvement, is rejected by the Hopi tribe, and raises far more questions and concerns than it could ever possibly resolve. The answer should be obvious, take the extra time to go through the generic docket, then circle back and consider a fair and just proposal in this case. RUCO would not oppose holding this case open for a Phase 2 proceeding like the Commission's approach in the recent TEP case.

The Commission should not decide the SCR deferral issue in this case.

Another issue that is at the forefront in this case but RUCO does not believe should be decided under the facts and circumstances concerns the SCR deferral. The relevant facts and circumstances are as follows. Arizona Public Service Company ("APS") filed its rate case on October 31, 2019 in accordance with the ACC's Decision No. 77270. RUCO-1 at 10. APS requested to include the costs of the recently completed installation of the Four Corners SCRs equipment, on Units 4 and 5 at the Four Corners Generating Station. Id. APS is one of the owners and is the operating agent of Four Corners located near Fruitland, New Mexico. Id. See APS-3, Attachment BDL-02RJ at 1. The installation of the SCRs is also included in this rate case. The SCRs were mandated by the Federal Government under the provisions of the

Clean Air Act. RUCO-1 at 10. The cost to APS for its share of the plant to install the SCRs was approximately $467 million[8] and its cost recovery is subject to a separate proceeding, E-01345A-16-0036, which has a pending recommended opinion and order (ROO issued 11/27/18). Id. The ROO ultimately concluded that the project was prudent, and the cost should be included in APS's base rates. Id. Id. at 11.

In this case, APS recommends that the ROO be "preserved", and the SCR project stay on its own separate path. APS-4 at 5. APS' proposed bill impact in this case includes the inclusion of the SCR project at Four Corners and the environmental upgrades discussed and in total the impact to ratepayers if approved will be $184 million or 5.6%. APS-4 at 5.

On January 22, 2020 APS issued a press release announcing its newly adopted Clean Energy Commitment which is centered around a goal to deliver 100 percent clean, carbon-free electricity to customers by 2050. RUCO-1 at 11, Exhibit FWR-3, RUCO-10. APS further announced that it will end all coal-fired generation by 2031, seven years sooner than previously projected. Id. The only coal fired generation that APS is scheduled to have in 2031 is the Four Corners Generating Station. RUCO-1 at 12. At this point the costs, savings and overall rate impact to APS' ratepayers associated with APS' Clean Energy Commitment is conjecture.

Thereafter, then Chairman Robert Burns wrote a letter to this Docket, on August 11, 2020, noting that with the early closure of Four Corners there will be stranded costs from the plant that will need to be recovered. RUCO-1, Exhibit FWR-5. Commissioner Burns requested that APS develop and submit a comprehensive analysis of the rate impacts, of the early retirement, for the Commission's consideration in this rate case. Included in this analysis,

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[8] The SCR equipment on Unit 5 was completed on December 17, 2017. The SCR equipment on Unit 4 was completed in April 2018. The cost of plant additions associated with this environmental compliance in 2017 and 2018 was approximately $467 million (APS response to Sierra Club Data Request # 2.4).

Commissioner Burn's specifically asked for the utility to examine the issue of "Securitization" to minimize rate impacts. Id. Securitization is a financing mechanism that allows a utility to recover costs by issuing bonds, with lower-than-normal financing costs, thereby saving customers money. Chairman Burns also asked the Company to review scenarios where the plant was to be retired in 2026 and 2029. Id.

While there have been some filings that have responded to Chairman Burns issues, from RUCO's standpoint these filings, like the CCT proposal, raise more questions than answers. For example, Ms. Lockwood discusses Securitization at length in her rebuttal testimony. APS-2 at 15-19. Ms. Lockwood discussed how Securitization could be accomplished given the complex array of legal, regulatory, and financing issues involved. APS-2 at 17. Some intervenors suggest legislation might not be necessary, but legislation is needed to make the securitized bonds marketable and to obtain the low interest rates needed to reduce costs to the utility's customers. Id. RUCO does not disagree with APS - there are clearly hurdles which need to be addressed with Securitization which furthers RUCO's point that there are too many important aspects that need to be understood and reviewed as part of the Commission's consideration of the SCR deferral.

APS' decision to end all coal generation by 2031 completely changed the circumstances of the SCR deferral. From the ratepayer's perspective, APS now intends to retire the plant seven years after having recently invested approximately $465 million. RUCO-1 at 15 (The SCR equipment on Unit 5 was completed on December 17, 2017. RUCO-1 at 11. The SCR equipment of Unit 4 was completed in April 2018. The total cost of the plant additions in 2017 and 2018 was approximately $467 million. Id.). Forty percent of the 5.6% increase in rates APS is requesting is solely attributed to paying for the SCRs - that now, right after APS spent $467 million, APS intends to dispose of seven years early. Id. These are not the circumstances that ratepayers bargained for when the Company originally bought the Four Corners requests before the Commission for approval – nor are they the circumstances upon which the Commission originally based its approval.

Prudency is a time specific determination. In other words, it should not be something that should be second guessed with the benefit of hindsight. However, both prior and subsequent facts and circumstances should not be dismissed if they are later found to have been part or should have been part of the prudency determination. Moreover, unilateral decisions such as the Clean Energy Commitment made after a prudency determination, which change the financial dynamics of the decision are certainly fair to consider in determining the costs to be recovered from the ratepayer.

The Clean Energy Commitment that was initially introduced almost three months after the Company filed its rate case, raises the question of the prudence of the Company's decision to invest almost $500 million into the plant less than two years before the Clean Energy Commitment was announced. RUCO-3 at 11. The Company made the Clean Energy Commitment without consulting the Commission or other affected stakeholders. APS recognizes Securitization as a less costly way to address these issues but has not made a firm commitment to Securitization. APS now is asking that the Four Corners SCRs be included in rates from which APS will profit handsomely. Id. With the Clean Energy Commitment, ratepayers will be paying a return of and a return on Four Corners for the seven years beyond its useful life - seven years of use which APS, the ratepayers, the Commission, and other stakeholders originally intended and bargained. In addition, for those seven years beyond 2031, ratepayers will also have to pay for the alternative generation and its associated costs to replace the Four Corners generation. Sierra Club's testimony in this proceeding indicates that

APS would enjoy substantial savings if it were to retire Four Corners Units 4 and 5 as quickly as possible instead of in 2031. Id. at 11.

There are many questions which need to be answered before the Commission will have enough information to make an informed decision. RUCO is not casting aspersions at anyone; the facts and circumstances changed, and the result is an issue that is beyond the scope of this proceeding. RUCO urges the Commission to get this right the first time, and not rush to judgment unless and until it has the necessary facts to make an informed decision.

APS has made an operating expense income pro forma adjustment of $8.3 million to reflect the amortization of the SCR deferral over 10 years. RUCO-1 at 24. RUCO recommends the Commission reverse APS amortization adjustment. Id.

The Commission should reject the Advanced Energy Mechanism ("AEM")

As was the case with the CCT proposal, the Company in its rebuttal case proposed a new adjuster mechanism - the AEM[9]. APS-5 at 7. The idea behind the AEM is a vehicle to allow the Company to recover the costs associated with the significant clean energy investments the Company will make to meet its clean energy commitments. APS-5 at 5-6. According to Mr. Guldner, the AEM could include Energy Efficiency Expenses ("EE"), lost fixed costs associated with EE and distributed generation ("DG") revenue requirements. Id. at 6. Mr. Guldner further testified that it would be very difficult to meet its clean energy commitment

[9] RUCO would note that it is sympathetic to the idea that a party responds to direct testimony by sometimes modifying its direct case. That certainly is a prerogative of a party. However, in this case, APS has made several proposals that are more than slight modifications - they are completely new proposals. RUCO is leery of such proposals and suggests the Commission should also be skeptical because they are major proposals that were neither contemplated nor offered in its Direct case. This puts stakeholders as well as the Commission at a disadvantage as the proposals, such as this one is being offered for the first time more than half-way through the processing of the case - i.e. - less time for stakeholder and Commission analysis, and less overall review.

without the AEM. Id. But he did not say it would be impossible to recover the cost through traditional ratemaking. Id. Mr. Snook testified that the Company could use existing adjusters - DSMAC, REAC, and LFCR - for the recovery of the clean energy plan and base rates for the CCT. APS-29 at 16. Staff agrees with Mr. Snook's characterization and Staff recommends the Commission reject the AEM. S-15 at 48. Staff notes that the AEM is conceptual in nature and lacks the specificity to recommend approval at this point. Id.

What is important to keep in mind is that adjustment mechanisms are the exception to fair value in Arizona. *Scates v. Arizona Corporation Commission,* 118 Ariz. 531,535. 578 P.2d 612, 616 (App. 1978). Currently, APS has **seven** adjuster mechanisms. Transcript at 2530. The Commission has approved adjusters more as the rule than the exceptions that they truly are supposed to be.

In describing adjustment mechanisms, the Scates Court noted that permissible adjuster mechanisms allow rates to adjust for variations in "certain and narrowly defined *operating expenses.*" Id. The narrow focus of adjustment mechanisms result in what has been commonly referred to as single-issue ratemaking. As Mr. Higgens' explains, single-issue ratemaking occurs when utility rates are adjusted, or costs deferred in response to a change in cost item considered in isolation. AECC-1 at 26. Adjustor mechanisms should only be used in extenuating circumstances such as where the Commission is dealing with costs that are very volatile or outside the utility's control and might cause significant financial harm to the utility if there was not such a mechanism in place. Transcript at 4684.

Naturally, adjustment mechanisms are appealing to utilities because they view expenses in isolation and provide no incentive to keep the expenses down - the expenses are not scrutinized like they would be in a rate case. They also result in higher revenues overall since they cost ratepayers more than if recovered through traditional ratemaking. Transcript at 4687.

It is with sound reason that Arizona's constitution limits the Commission's latitude to set rates apart from a rate case that permits the examination of all costs and revenues. The Court in Scates acknowledged that such "piecemeal" ratemaking is "fraught with potential abuse" and serves "...both as an incentive for utilities to seek rate increases when cost in a particular case rise, and as a disincentive for achieving countervailing economies in the same or other area of their operations." *Scates v. Arizona Corporation Commission,* 118 Ariz. 531, 534. 578 P.2d 612, 615 (App. 1978).

There are numerous reasons why the AEM should be firmly rejected. Perhaps most importantly is that the costs can be recovered through traditional ratemaking and there is no need for extraordinary ratemaking at this time. Both the AEM and CCT were proposed late in the case and no intervenor has really had the ability to thoroughly investigate or analyze their appropriateness. With the CCT, APS provided no analysis justifying the funding it recommends, nor how the apportionment of costs between ratepayers and shareholders was derived. RUCO-3 at 7. The CCT proposal is in essence, a pledge by APS, without any input from the Commission or ratepayers or other stakeholders other than the Navajo Nation, to give away approximately $125 million of ratepayer money for amorphous "benefits", and which are wholly unrelated to cost of services to customers. Id. With respect to the Clean Energy Commitment, APS, via the AEM, seemingly seeks a blank check to do whatever programs and investments it undertakes, under the banner of clean energy and have ratepayers pay for it without any meaningful determinations regarding prudency, efficiency, cost-effectiveness, and the achievement of quantifiable goals. Id.

For the foregoing reasons, RUCO recommends the Commission reject the AEM.

Post Test Year Plant/Property Taxes on PTYP/Depreciation Expense on PTYP

RUCO proposes reducing the Company's proposed amount of post-test year plant additions from the requested amount of $773.3 million to $608 million. RUCO-3 at 15. RUCO removed post-test year projects whose total costs were less than $5 million as these projects were so small compared to the Company's overall construction budget which nears almost $1 billion. Excluding them from the rate base would not impair the utility's financial health. Id.

The Commission in Decision No. 71410, addressed the issue of PTYP in 2009. Decision No. 71410 was a rate case involving various water and wastewater systems of Arizona-American Water Company. The Commission in that case noted:

> Staff recommends exclusion of proposed plant in the amount of $2,046,765 in the Agua Fria water district: $610,732 in pro forma adjustments in the Mohave Water District: and $3,932,080 relating to the Wishing Well Wastewater Treatment Facility ("WWTP") in the Mohave Wastewater district, all because the plant was not in service prior to the end of the test-year. RUCO recommends a downward adjustment of $2,138,020 to Mohave Wastewater's rate base, contending that this represents a portion of the WWTP that is not used and useful.
>
> As Staff explains, Commission rules require the end of the test-year, which is the one-year historical period used in determining rate base, operating income and rate of return, to be the most practical date available prior to the filing. A utility has the freedom to choose a test-year that includes all major rate base and operating income items needed to support its rate application, and to include pro forma adjustments to its chosen test-year. ***Matching is a fundamental principle of accounting and ratemaking, and the absence of matching distorts the meaning of, and reduces the usefulness of, operating income and rate of return for measuring the fairness and reasonableness of rates***. Staff contends that the matching principle is the reason that the Commission has allowed inclusion of post test-year plant in rate base only in ***<u>special and unusual situations</u>*** that warranted the recognition of post test-year plant. ***Staff states that it has traditionally recognized two scenarios in which Staff believes recognition of post test-year plant is appropriate: (l) when the magnitude of the (1) investment relative to the utility's total investment is such that not including, the post test-year plant in the cost of service would jeopardize the utility's financial***

> ***health, and (2) when certain conditions exist as follows: (a) the cost of the post test-year plant is significant and substantial, (b) the net impact on revenue and expenses for the post test-year plant is known and insignificant or is revenue neutral, and (c) the post test-year plant is prudent and necessary for the provision of services and reflects appropriate, efficient, effective, and timely decision-making.***[10] (Emphasis added).

Decision No. 71410 at 19-20. The Commission ultimately denied much of the post-test year plant in the Agua Fria and Mohave Water systems. The Commission explained that the Company failed to show any "special or unusual" circumstances to justify the inclusion of the plant." Decision No. 71410 at 20-23.

Somewhere in the last 10 years the matching principle[11], as Staff explained above was the underlying basis for the Commission's allowance of PTYP, has been cast aside, and has given way to some utilities pushing the bounds of Arizona's regulatory ratemaking process. In truth, it is no longer a test-year; it is "test-years", one 12-month test year for plant, and an additional 12-months for post-test year plant. Again, to quote the Commission's recitation of Staff's position in Decision No. 71410, "the absence of matching distorts the meaning of, and reduces the usefulness of, operating income and rate of return for measuring the fairness and reasonableness of rates." The distorted meaning and the unfairness to ratepayers of the Company and Staff's PTYP recommendation are apparent under the facts and circumstances in this case.

RUCO has sought on a case-by-case basis some policy clarity on the issue of PTYP. The utilities, however, treat PTYP as a given - it must be all the PTYP for one year beyond the test year. To APS' credit, APS is the only company that has agreed to rolling forward the TY A/D balance for one year. RUCO agrees, and does acknowledge APS' adjustment, which is

[10] Footnotes excluded – footnotes referenced testimony to support decision.

why RUCO's PTYP adjustment is only to remove small projects. RUCO has agreed to include $608 million, close to 80% or APS' total PTYP request which is a substantial amount and is fair to the Company. RUCO-3 at 16. RUCO-1 at 10. There is nothing "special or unusual" about the projects and the items RUCO excluded are small projects, less than $5 million. By comparison, APS's rate base at the end of the test year was $8.5 billion. RUCO-3 at 17.

Thus, $0.130 billion out $8.5 billion represents an increase in rate base of 1.5%. This relatively small amount of money cannot be considered significant when compared to the utility's total investment nor has there been any showing by the utility that excluding this amount from the rate base would jeopardize its financial health. RUCO's relatively minor adjustment to PTYP is fair and reasonable, consistent with the Commission's prior decisions and should be adopted.

RUCO also recommends eliminating the Company's proposed inclusion of $11.1 million of property taxes associated with post-test year plant additions. Id. at 17. There is a lag between when utility plant is placed in service and the plant appears on the tax assessor's tax rolls and the utility must pay property tax on that property. Id. The reason for the lag is that the plant must be placed into service then reported to the tax assessor who then calculates a tax rate for an upcoming period (generally the next fiscal or calendar year) and bills the utility at the assessed rate based on that historic plant balance. Id. In the last APS rate case APS acknowledged that the lag time between when the utility plant is placed in service and the time the utility is obligated to pay property tax is two years. Id.

The Company disagrees with RUCO's adjustment on several grounds. First, the Company argues that at some point in the future the Company will have to pay property taxes

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[11] Which as the Company has made clear is very important when it comes to COC updates.

on the property and therefore the taxes are a known and measurable amount and should be included in rates Id. at 18. Second, by including the anticipated expense in rates it allows the utility recovery for the period between when new rates go into effect and the next rate case. Id. Finally, if RUCO's proposal is approved, APS's cash working capital allowance, and hence its rate base, would need to be increased accordingly. Id.

The Commission should dismiss APS' arguments for several reasons. First, there is no dispute that there is a lag of two years between when utility property is placed in service and when the utility is obligated to pay property tax expense on it. Second, the cases that the Company relies on to support their position were all approved settlements and settlements have no precedential value. Third, the property taxes associated with the post-test year plant and the associated property tax expense will not be incurred in the PTY - so why include it in rates? Id.

Consistent with RUCO's recommendation to allow only PTYP that was placed in service that is significant, over $5 million, the Commission should also adjust the pro forma depreciation expense associated with the excluded PTYP which would result in a reduction of $ 7.9 million. RUCO-1 at 25.

The Commission should approve RUCO's PTYP and associated property tax recommendation - it is fair and will help reduce the impact on ratepayers of the prior and possibly current rate increase.

Cash Incentive

RUCO recommends the elimination of $25.592 million of the $32.789 million of cash incentives that APS paid its employees as bonus in the test year. Id. at 13. The bonuses are largely tied to improving APS's financial performance rather than customer service which, given the poor customer service issues would be a better target. Id. The Company believes that cash incentive is a valid cost available to employees for their participation in meeting goals that align the success of the business with the interests of APS customers. APS-13 at 18. The Company notes that no party claims that the expense is “excessive” or unreasonable. Id.

The Company misses the point. The issue is not the amount, its reasonableness, or its excess. The issue is who should pay for an expense which benefits the shareholders at least as much as the ratepayers. The Company witness, Elizabeth Blankenship testified that the financial portion of the incentive compensation amounts to approximately 54% for the test year. Transcript at 1550. Ms. Blankenship also agreed that ratepayers and shareholders share equally in achieving the financial goals. Id. Ratepayers, however, are already paying for the full cost of employee salaries, health benefits, pension, etc. - should they pay for the full recovery of bonuses too? When asked, the Company’s response is they want to offer an incentive package in line with their peers. Id. at 1551. Nobody is suggesting that APS offer anything less - again the issue is simply who should pay for it. RUCO’s adjustment removes the portion of the incentive compensation expense that is directly tied to the benefit of shareholders and allocates it to shareholders. The portion where both shareholders and ratepayers can benefit should be allocated equally between shareholders and ratepayers and that is what the RUCO adjustment does. This methodical approach provides an appropriate balance between the benefits attained by both shareholders and ratepayers and my adjustment should be adopted. The Commission should approve RUCO’s recommendation.

Industry Association Dues

APS has removed the portion of expense that relates directly to the legislative and regulatory advocacy of membership in EEI. RUCO-3 at 15. RUCO is recommending that the remaining portion of the industry dues be recovered proportionally between ratepayers and shareholders, consistent with past Commission decisions on the issue. RUCO-3 at 15.

For example, the Commission has approved a 50/50 sharing between ratepayers and shareholders on this issue in several proceedings including Decision Nos. 71914 and 70860. RUCO-1 at 22. In the 2010 UNS Electric rate case, Decision No. 71914, referring to Decision No. 70360, the Commission noted "we adopted Staff's position and disallowed 49.93 percent of EEI dues because EEI's core dues related to legislative advocacy, regulatory advocacy, advertising, marketing, and public relations total 49.93 percent of the total dues." Decision No. 71914 at 25. The Commission recognized and continues to recognize that expenses that benefit both the ratepayer and the shareholder should not be the full cost burden of the ratepayer. EEI is not unique in the fact that the expense benefits both ratepayers and shareholders. Other membership dues have similar dual benefits. RUCO-1 at 22.

Because of the duality of benefits, which no party denies, RUCO recommends all membership dues be shared 50/50 between ratepayers and shareholders and recommends operation and maintenance expenses be reduced by $1,791,178. Id. at 22.

Executive Compensation

Pinnacle West pays its executives to both perform well, both operationally and financially. In theory, ratepayers who receive service from a well operated company, providing affordable, efficient, and reliable electricity service, derived from prudent decision making, should pay their fair share of compensation. Whether APS has, in fact, met these criteria is a separate issue for resolution by the Commission, and one that RUCO questions. RUCO-3 at 3. This case raises serious questions regarding customer service adequacy, resource planning, and proposed dates for the retirement of existing generation assets.

Regardless, shareholders benefit from executives whose work results in good financial performance compared to their peer companies and shareholders should be willing to pay market-based rates for that service. The question here, like many other issues in this case, is not the amount of the cost but how to allocate the cost between the ratepayer and the shareholder. The Company's conclusion that executive pay is a prudent cost and hence should be the entire burden of the ratepayer dismisses the fact that the shareholder derives as much if not more benefit than the ratepayer from the expense. The Commission has made it clear that where there is benefit by both the shareholder and the ratepayer each should contribute - anything less is not fair. RUCO recommends the executive pay be shared - RUCO recommends the recommended 2019 base salaries be reduced by 50% which results in a reduction in operation and maintenance expense of $12.2 million[12]. Id. at 3.

Directors and Officers Insurance Expense

RUCO believes this expense should also be shared between shareholders and ratepayers as both benefit from this insurance protection. Shareholders, as a body, receive a benefit, as this insurance pays for litigation costs and liabilities resulting from a claim made against the Company. RUCO-1 at 23. It is helpful for ratepayers to have this type of insurance to attract and retain qualified Directors and Officers and, therefore, protect them from personal liability claims during a lawsuit. RUCO's recommendation reduces Directors and Officers Insurance expense by $376,176. Id. Staff made a similar adjustment. Staff-1 at 45.

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[12] During the hearing APS' counsel raised questions regarding RUCO's $12.2 million number and whether that was an accurate representation of the base salary RUCO used. RUCO's information was based on a response APS made to Chairman Burn's letter of October 9, 2020, but Mr. Radigan acknowledged his number may have been in error. Transcript at 4212 and 4216. The Company's point was well taken - RUCO went back and looked at the relevant APS schedules and Responses but has found no data to date to revise its recommendation.

Regulatory Asset Amortization

RUCO proposes to accelerate the reduction of stranded costs that will occur as the result of the Company Clean Energy Commitment. RUCO-1 at 25. RUCO recommends a pro-forma adjustment to depreciation and amortization expense in the amount of $80 million per year. Id. At the end of the test year, APS had $1,283,538 in regulatory assets which are included in rates and the ACC jurisdictional amount of these assets are included in rate base for full cost recovery, at the Company's weighted average cost of capital. RUCO-1 at 25. Among the list of APS' regulatory assets are the stranded costs of the retired Navajo Plant at $82.8 million. RUCO - 1 at 25, Exhibit FWR-21. Also on the list is another $17.8 million liability for the Navajo coal mine reclamation, an $81.1 million balance on the retired units at the Cholla generating station and another $17.4 million in other stranded costs related to other production plant assets. These production plant assets totaled $199.1 million.

With the Clean Energy Commitment this stranded asset list will continue to grow and ratepayers will be left to fund a return of and return on assets that will not be used and not be useful. RUCO is very concerned about this and believes stranded costs should be eliminated as soon as is practically possible. Since RUCO has recommended that the Four Corners SCRs not be reflected in rates, until such time the true rate impact of the Clean Energy Commitment and Securitization can be examined, this adjustment reduces the requested revenue requirement. Id. With that adjustment and the decreased revenue requirement, there is sufficient cash flow to accelerate the elimination of stranded costs.

By including this cash flow in the Company's depreciation and amortization expense, RUCO estimates that the outstanding production of plant regulatory assets would be eliminated by the end of 2020. Id. at 25-26. After the existing production plant related stranded costs are eliminated this cash flow could be returned to ratepayers as an adjustor mechanism, refunded or retained and used to write down other future production related stranded costs (i.e., Chola and Four Corners). Id.

Depreciation

The calculation of depreciation expense is another area where the Commission can reduce the impact of higher rates with little or no impact to the company. Depreciation rates are not an exact science and the Commission should consider its ability and discretion in approving rates as another arrow in its quiver to help with the increased rate impacts resulting from rate cases.

The proposed depreciation rates in this case are the result of the Company's Depreciation Study. RUCO recommends the Commission approve the depreciation study and proposed rates subject to modifications. RUCO-3 at 27. A depreciation study is the process whereby each account is examined to determine the appropriate survivor curve, average service life, and net salvage rate to be used in the calculation of depreciation rates, thereby allowing calculation of depreciation expense, which would allow the utility to properly recover its invested capital. RUCO-1 at 32. This depreciation expense calculation is then circulated to a utility's revenue requirement department where it is combined with other utility costs such as operations and maintenance costs, return on investment costs, taxes, etc., to compute a total revenue requirement. Id. RUCO provided a detailed background and explanation of the finer points of Depreciation in Mr. Radigan's Direct Testimony. RUCO-1 at 27-43. RUCO would refer the reader to the testimony for the details. While technical and very detailed, depreciation and the study made, and the calculations used are very important as depreciation rates and related expenses have a substantial impact in setting rates.

The first modification is to the Company's average service lives. There are four parts in the depreciation study used to compute the average service lives. RUCO-1 at 32. Part 4 of the study is titled analysis, but no analysis is presented. RUCO-1 at 33. The only thing shown in the study is an example of the mathematical results of a deprecation analysis for one account: Account 367 – Underground Conductors and Devices[13]. Id.

This part of the study is truly problematic because Part 4 is the true essence of analyzing the depreciation rates - it is supposed to show the mathematical results which must be analyzed to develop depreciation rates. Usually what is Included in this mathematical analysis is the historical plant data, the retirement data, the observed life table derived from the plant history and retirements, net salvage data, the results of mathematical curve fitting and a presentation of data used to develop the accrual rates. Id. However, in APS' study there is no discussion of the proposed changes contained in the study or the basis for the changes. The depreciation study as presented gives no indication of why its results are reasonable and should be adopted. Id.

As to individual plant accounts, RUCO's modifications and recommendations - based on mathematical curve fitting and then graphing that analysis against the observed life table to determine the best fitting Iowa curve[14], are as follows:

Account 361 - Station Equipment - Company's proposed curve is below the observed life table starting at the year 40. RUCO's proposed R3 Iowa Curve with a 65-year average

[13] In discovery, the Company did provide over 1,300 pages of the mathematical results for the rest of the plant accounts, but no written narrative analysis was provided.
[14] RUCO-3 at 19

service life fits the observed life data better and is closer to the indicated average service life. Id. at 34.

Account 362 - Station Equipment - Company proposes an average service life of 45 years with a L0.5 Iowa Curve. Id. at 35. RUCO recommends a 48-year average service life as the Company's represents too short a service life. Id.

Account 364 - Steel - Company proposes 50-year service with an R0.5 curve. Id. RUCO recommends a service life of 65 years as relevant data from the longest observation band of 2004-2018 indicate average service life is 68 years. Id. at 36.

Account 365 - Overhead Conductor and Devices - RUCO recommends a 55-year averaged with a LO curve as it best fits the various Iowa curves and service lives shown by the data for this account. Id.

Account 366 - Underground Conduit - The current average service life is 60 y with a L1 curve. Id. at 37. RUCO recommends a service life of 70 years as relevant data from the observation band of 1971-2018 indicate that the best fitting curves show an average service life of 70 years which is what RUCO recommends.

Account 367 Underground Conductors - The current average service life is 40 y with a L1 curve. Id. at 37. RUCO recommends a service life of 44 years as relevant data from the observation band of 1971-2018 indicate that the best fitting curves show an average service life of 44 years which is what RUCO recommends. Id. at 37.

Account 369 Services - The current average service life is 40 y with a L1 curve. Id. at 37. RUCO recommends a service life of 65 years with a R0.5 curve as the data shows the best fitting curves have average service lives of 75-85 years and RUCO's below average 65-year recommendation is a necessary and positive step to start using the average life closer to the indicated average service life. Id. at 38-39.

Account 370.03 AMI - Company believes that a 15-year average service life should be used but offers no explanation. In RUCO's experience the most common service life being used by utilities is 20 years and is the expected service life being quoted by AMI vendors. In addition, Nevada Power which serves the Las Vegas area and has been installing AMI meters since 2010 uses a 20-year average service life and has had two deprecation studies filed with the Nevada Commission. RUCO recommends the 20-year service life given that the utility has not provided any support for its recommended change. Id. at 39.

Account 371 - Installations on Customer Premises - Company recommends 40-year average with LO curve. The mathematical curve fitting for this account shows the best fitting curves indicate a 46-year average service life which is the basis for RUCO's recommendation. Id. at 40.

Account 373 - Street Lighting and Signal systems - Company recommends 55-year average with LO curve. The mathematical curve fitting for this account shows the best fitting curves indicate a 60-year average service life. This curve is a much more reasonable but still conservative estimate given that the best fitting curves indicate an average service life of over 90 years. Id. at 41.

The second area of concern with the Company's depreciation study concerts the Net Salvage Analysis. Id. The concern focuses on two accounts. Account 365 – Overhead Conductors and Devices and Account 367 – Underground Conductors and Devices. Id. at 41-42.

The Company proses to increase net salvage from -10% to -20% in Account 365. This proposal increases depreciation expense by $1.1 million per year. Id. The historic data does not support the Company's proposal, however, because for the period 1993-2015, the historic net salvage for this account was -10%. Id. The weighted average has increased to -22% since that time - it should be pointed out, however, that was driven by a negative gross salvage value in 2017 of $2.5 million which is an abnormality as costs are usually not incurred when salvaging property. Id. The Company offers no explanation in the Company's study on why this abnormal data entry exists or why it should be considered in the analysis for this account. Without such an explanation, it is unsupported and should be rejected.

With Account 367, the historic data which shows net salvage data from 1993-2018 shows the weighted average net salvage for this account is -5.5%. Id. The Company's depreciation study provides no explanation for the proposed change. Given that the historic data shows the current net salvage rate to be in line with history and the Company has provided no explanation to support its change, it also should be rejected.

In total, with the above modifications, the pro forma expense proposed by the Company should be reduced by $27.9 million. Id. at 43.

Rate Design

RUCO agrees with the Company that the best outcome of this case is to spread the retail revenue change equally across customer classes, which in this case would result in 0.63% rate decrease for every class. RUCO-2 at 1.

For the rate design relating to the twelve residential rate subclasses, RUCO recommends 1) adding a second TOU rate class to give customers better optionality, 2) freezing the R-2 rate class from accepting new customers, 3) modifying the annual reassignment of rate classes to favor customer choice 4) simplifying the customer bill format, and 5) renaming the formal service class names to make them more explanatory.

For the rate design within rate classes, RUCO recommends the base rate change for each residential rate subclass be recovered by 1) retaining the existing customer service charges, 2) retaining the super off-peak energy charge, 3) and changing the remaining demand and energy rates proportionally to recover the targeted rate change for the service class. Id. at 2.

1. Second TOU rate class/Freezing R-2 rate class

The Company's residential customers have peak demands in the early evening, during the summer months, corresponding with the ambient outside temperature. RUCO-2 at 14. It stands to reason that the hotter it is outside the larger the demand will be, due to increased air conditioning demand. This is true regardless of average usage or rate class. Id. Proponents of demand rates argue that their higher on peak pricing encourages those customers to move load to off-peak periods. It is also true that customers that are on demand rates and have a lifestyle which result in low load factors, have higher bills on a demand rate, as compared to an energy only rate. Id.

Whatever one's load requirements, customers should be encouraged to shift load to off peak periods. RUCO recommends that a second TOU rate option be enacted to give customers further optionality in rate options to manage their electric bills.

RUCO's proposed second rate class would have a $0.50 per day service charge which equates to $15 per month for a 30-day month and roughly equal to the service charge paid by the Basic Service Class customers. R-2 at 14. The off-peak rate would be set at 7 cents per kWh, which is 33% to 45% lower than the corresponding energy rate for the remaining non-demand residential rate offerings. Id. At 14-15. This discount is given to encourage customers to shift load to off-peak periods. The on-peak energy rate is 25 cents per kWh, which is 8% higher based on existing TOU rates and 125% higher based on existing flat rates than the corresponding energy rate, for the remaining non-demand residential rate offerings. Id. These 25 cents per kWh on-peak rate is set to encourage customers to shift load to off-peak periods. The 7 cent per kWh off-peak rate is set at a discount to other energy only rates to encourage customers to shift load to off-peak periods. With a 20% on-peak 80% off-peak energy usage, the average rate under this service class would be 11.3 cents per kWh which would be a 4% discount from the lowest residential rate class, R-3. Id. If the customer increases on-peak usage from 20% to 22% they would lose the discount. Id. At 15.

RUCO believes this mixture of carrot and stick will entice only customers that are truly committed to shifting load to the off-peak period to sign up for this rate. Id.

RUCO also believes that freezing the R-2 rate class is warranted as the availability of a demand rate and its attendant price signals has not resulted in a meaningful shift of load by customers. Id. With no discernible positive results from the offering of a demand rate and the confusion and complaints they have caused, RUCO believes it prudent to de-emphasize APS's three-part rate offerings, with demand charges.

2. Customer Choice in Rate Design

The customer frustration with the changes to rate design as the result of the last rate case is well-known. The mandatory nature of those customers who were involuntary migrated to a different service plan raised numerous issues which were addressed at length in the Alexander report. See RUCO-15. RUCO agrees with the Alexander Report's conclusion that mandatory migration without customer education should not be allowed. RUCO-2 at 17.

3. Bill Format/Renaming Service Class Names

Again, given the level of customer frustration and difficulties associated with the new rate designs these two issues should be a given. The bill format is difficult to understand, arranged poorly and provides too much detail. RUCO-2 at 18-19. A typical TOU bill for example, is split into two columns and lists on the left-hand side 24-line items of charges. RUCO-2 at 19. The information on the right-hand side gives information on energy use by time and comparisons of this year's usage to last year's if available. While some of the information on this sheet is valuable it is so full of information it takes on the appearance of white noise. Id. This format is so busy it loses its value as a tool to convey to the customer of when and how they use energy.

Among RUCO's recommendations, it would be better to move most non-essential parts of the bill to a new page or to the web where customers who are interested in learning more could take their time to do so. Id. The items on the right-hand side could be enlarged and expanded to give more meaningful information to the customers. Other options would include allowing customers to select a bill type, either brief or detailed, based on their individual preference. Id. If implemented properly, this would likely improve the customers' ability to understand its rate offerings. Id.

The rate class names were another source of confusion and complaints. Id. at 20. A review of the formal class names shows they are biased to directing customers to the demand rate options to maximize savings. Id. at 20. Unfortunately, customers with low load factors do not do well financially under demand rates. It is likely that the poor rate class name choices combined with unattractive financial consequences of low load customers on demand rates contributed to the number of complaints received. Id.

The current names of rates classes are meaningless at best and dangerous at worst, given that many of them imply that customers will save money by switching to them. Id. at 21. RUCO recommends the following class name changes:

Table 4

Current Name		Proposed
XS	– Lite Choice	Small Flat Rate
Basic	– Premier Choice	Medium Flat Rate
Basic -L	– Premier Choice Large	Large Flat Rate
TOU	– Saver Choice	TOU
		TOU – Off Peak
R-2	– Saver Choice Plus	Demand Rate
R-3	– Saver Choice Max	Large Demand
R-Tech	– Saver Choice Tech	Large Demand w-TECH

Id.

APS offered proposed names in its late-filed exhibit which RUCO believes are like RUCO's proposal and RUCO would not object. APS-86 at 2.

Rate Design Changes within a rate class

As to rate design within a rate class RUCO recommends adopting the approach proposed by the Company, which is to minimize changes, to avoid confusion. Id. RUCO recommends revenue changes for each service class be allocated within the service class using the following guidelines: 1) retain the existing customer service charge, 2) retain the super off-peak energy charge for the TOU rate class, 3) allocate the rate change to the remaining demand and energy rates equally to recover the targeted rate change for the service class. Id.

Conclusion

For all the above reasons the Commission should approve RUCO's recommendations.

RESPECTFULLY SUBMITTED this 6th day of April, 2021.

S/ Daniel W. Pozefsky
Daniel W. Pozefsky
Chief Counsel

ORIGINAL of the foregoing will be
e-filed this 6th day of April 2021 with:

https://efiling.azcc.gov
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By *s/ Renee de la Fuente*
Renee de la Fuente

RESIDENTIAL UTILITY CONSUMER OFFICE

BEFORE THE ARIZONA CORPORATION COMMISSION

DOCKET NO. E-01345A-19-0236

RUCO SCHEDULES FOR INITIAL BRIEF

SCHEDULES A, B, C AND H

April 6, 2021

TABLE OF CONTENTS

ARIZONA PUBLIC SERVICE COMPANY
COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS
ACC JURISDICTION
ADJUSTED TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	Electric: Original Cost	Electric: RCND	Electric: Fair Value	Line No.
1.	Rate Base	$ 8,370,104 (a)	$ 15,136,256 (a)	$ 11,753,180	1.
2.	Operating Income	687,215 (b)	687,215 (b)	687,215 (b)	2.
3.	Current Rate of Return	8.21%	4.54%	5.85%	3.
4.	Required Operating Income	554,101	554,101	554,101	4.
5.	Required Rate of Return on OCRB	6.62% *	3.66% *	4.71% *	5.
6.	Operating Income Deficiency on OCRB	(133,114)	(133,114)	(133,114)	6.
7.	Gross Revenue Conversion Factor	1.3288 (c)	1.3288 (c)	1.3288 (c)	7.
8.	Increase in Base Revenue Requirements Based on OCRB	$ (176,882) **	$ (176,882) **	$ (176,882) **	8.
9.	After Tax Return on Fair Value Increment			445	9.
10.	Requested Increase in Base Revenue Requirements			$ (176,437)	10.
11.	Required Rate of Return with Fair Value Increment				11.

Line No.	Customer Classification	Present Rates 1, 2 ($000)	Projected Revenue Increase Due to Base Rates	Base Rate % Increase	Adjustor Transfers 3 ($000)	Total Rate Change	Bill Impact % Increase	Line No.
12.	Residential	$ 1,740,264	$ (87,850)	-5.05%	$ 55,268	$ (32,582)	-1.87%	12.
13.	General Service	$ 1,476,858	$ (85,467)	-5.79%	$ 57,816	$ (27,651)	-1.87%	13.
14.	Irrigation and Water Pumping	$ 32,188	$ (1,977)	-6.14%	$ 1,374	$ (603)	-1.87%	14.
15.	Outdoor Lighting	$ 20,814	$ (797)	-3.83%	$ 407	$ (390)	-1.87%	15.
16.	Dusk-to-Dawn	$ 9,067	$ (347)	-3.82%	$ 177	$ (170)	-1.87%	16.
17.	Total	$ 3,279,191	(176,437)	-5.38%	$ 115,042	$ (61,395)	-1.87%	17.
18.								

Notes:

* The Rate of Return for OCRB, RCND and Fair Value does not reflect the need for a return on the difference between Fair Value Rate Base and Original Cost Rate Base but is simply a mathematical derivation based upon the original cost rate of return.

** Does not include the fair value increment reflected on Line 9.

Supporting Schedules:
(a) B-1
(b) C-1, page 2 of 2
(c) C-3
(d) H-1

Recap Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

		Original Cost						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year Ended 6/30/2019 (a) (A)	Pro Forma (a) (B)	Adjusted Test Year Ended 6/30/2019 (a) (C)	Unadjusted Test Year Ended 6/30/2019 (a) (D)	Pro Forma (a) (E)	Adjusted Test Year Ended 6/30/2019 (a) (F)	Line No.
1.	Gross utility plant in service	$ 20,668,805	93,784	$ 20,762,589	$ 17,522,166	$ 83,445	$ 17,605,611	1.
2.	Less: Accumulated depreciation & amortization	7,267,041	519,699	7,786,740	6,323,177	$ 508,564	6,831,741	2.
3.	Net utility plant in service	13,401,764	(425,915)	12,975,849	11,198,989	(425,119)	10,773,870	3.
	Deductions:							
4.	Deferred income taxes	1,908,074	(30,832)	1,877,242	1,903,462	(30,657)	1,872,805	4.
5.	Deferred investment tax credits (b)	197,749		197,749	196,585		196,585	5.
6.	Customer advances (b)	174,411		174,411	145,118		145,118	6.
7.	Customer deposits	81,423		81,423	81,423		81,423	7.
8.	Liabilities for pension benefits	305,207		305,207	280,177		280,177	8.
9.	Liability for asset retirements (b)	744,955		744,955	741,379		741,379	9.
10.	Other deferred credits	11,807		11,807	10,827		10,827	10.
11.	Coal mine reclamation (b)	197,443		197,443	196,800		196,800	11.
12.	Unrecognized tax benefits (b)	42,313		42,313	35,241		35,241	12.
13.	Operating lease liabilities (b)	111,553		111,553	99,615		99,615	13.
14.	Regulatory liabilities	2,008,573	(190,188)	1,818,385	1,988,207	(176,096)	1,812,111	14.
15.	Total deductions	5,783,508	(221,020)	5,562,488	5,678,833	(206,753)	5,472,080	15.
	Additions:							
16.	Regulatory assets	1,283,538	97,117	1,380,655	1,197,115	95,915	1,293,030	16.
17.	Other deferred debits	38,202		38,202	32,909		32,909	17.
18.	Nuclear Decommissioning trust (b)	950,448		950,448	945,886		945,886	18.
19.	Other special use funds (b)	241,558		241,558	240,398		240,398	19.
20.	Assets for other postretirement benefits (b)	52,611		52,611	48,297		48,297	20.
21.	Operating lease right-of-use assets (b)	174,320		174,320	155,663		155,663	21.
22.	Allowance for working capital (c)	384,155	(10,486)	373,669	361,755	(9,626)	352,129	22.
23.	Total additions	3,124,832	86,631	3,211,463	2,982,024	86,289	3,068,313	23.
24.	Total rate base	$ 10,743,088	$ (118,264)	$ 10,624,824	$ 8,502,181	$ (132,077)	$ 8,370,104 (d)	24.

Supporting Schedules:
(a) B-2
(b) E-1
(c) B-5

NOTE: There may be variances in displayed values due to rounding.

Recap Schedules:
(d) A-1

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS
TOTAL COMPANY AND ACC JURISDICTION
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

		RCND						
		Total Company			ACC			
Line No.	Description	Unadjusted Test Year Ended 6/30/2019 (a) (d) (A)	Pro Forma (a) (B)	Adjusted Test Year Ended 6/30/209 (a) (C)	Unadjusted Test Year Ended 6/30/2019 (a) (d) (D)	Pro Forma (a) (E)	Adjusted Test Year Ended 6/30/209 (a) (F)	Line No.
1.	Gross utility plant in service	$ 39,632,048	$ 93,784	$ 39,725,832	$ 33,598,427	$ 83,445	$ 33,681,872	1.
2.	Less: Accumulated depreciation & amortization	14,668,992	$ 519,699	15,188,691	12,763,742	$ 508,564	13,272,306	2.
3.	Net utility plant in service	24,963,056	(425,915)	24,537,141	20,834,685	(425,119)	20,409,566	3.
	Deductions:							
4.	Deferred income taxes	3,608,594	(30,832)	3,577,762	3,599,871	(30,657)	3,569,214	4.
5.	Deferred investment tax credits (b)	197,749	-	197,749	196,585	-	196,585	5.
6.	Customer advances (b)	174,411	-	174,411	145,118	-	145,118	6.
7.	Customer deposits	81,423	-	81,423	81,423	-	81,423	7.
8.	Liabilities for pension benefits	305,207	-	305,207	280,177	-	280,177	8.
9.	Liability for asset retirements (b)	744,955	-	744,955	741,379	-	741,379	9.
10.	Other deferred credits	11,807	-	11,807	10,827	-	10,827	10.
11.	Coal mine reclamation (b)	197,443	-	197,443	196,800	-	196,800	11.
12.	Unrecognized tax benefits (b)	42,313	-	42,313	35,241	-	35,241	12.
13.	Operating lease liabilities (b)	111,553	-	111,553	99,615	-	99,615	13.
14.	Regulatory liabilities	3,084,207	(190,188)	2,894,019	3,052,935	(176,096)	2,876,839	14.
15.	Total deductions	8,559,662	(221,020)	8,338,642	8,439,970	(206,753)	8,233,217	15.
	Additions:							
16.	Regulatory assets	1,283,538	97,117	1,380,655	1,197,115	95,915	1,293,030	16.
17.	Other deferred debits	38,202	-	38,202	32,909	-	32,909	17.
18.	Nuclear Decommissioning trust (b)	950,448	-	950,448	945,886	-	945,886	18.
19.	Other special use funds (b)	241,558	-	241,558	240,398	-	240,398	19.
20.	Assets for other postretirement benefits (b)	52,611	-	52,611	48,297	-	48,297	20.
21.	Operating lease right-of-use assets (b)	174,320	-	174,320	155,663	-	155,663	21.
22.	Allowance for working capital (c)	384,155	(10,486)	373,669	361,755	(9,626)	352,129	22.
23.	Total additions	3,124,832	86,631	3,211,463	2,982,024	86,289	3,068,313	23.
24.	Total rate base	$ 19,528,226	$ (118,264) (d)	$ 19,409,962 (d)	$ 15,376,739	$ (132,077) (d)	$ 15,244,662 (d) (e)	24.

Supporting Schedules:
(a) B-3
(b) E-1
(c) B-5
(d) B-4a

NOTE: There may be variances in displayed values due to rounding.

Recap Schedules:
(e) A-1

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(1) UPDATED FOR REBUTTAL Actual at End of Test Year 6/30/2019 (a) Total Co. (A)	(a) ACC (B)	(2) Fossil Generation Post-Test Year Plant Additions Total Co. (C)	ACC (D)	(3) Nuclear Generation Post-Test Year Plant Additions Total Co. (E)	ACC (F)	(4) Distribution and IT/Facilities Post-Test Year Plant Additions Total Co. (G)	ACC (H)
1.	Gross Utility Plant in Service	$ 20,668,805	$ 17,522,154	$ 158,904	$ 158,142	$ 44,025	$ 43,814	$ 360,286	$ 348,268
2.	Less: Accumulated Depreciation & Amort.	7,267,041	6,323,177	201,688	200,720	17,283	17,200	287,026	276,835
3	Net Utility Plant in Service	13,401,764	11,198,977	(42,784)	(42,578)	26,742	26,614	73,260	71,432
4.	Less: Total Deductions	5,783,508	5,659,096	9,637	9,591	(623)	(620)	4,315	4,180
5.	Total Additions	3,124,832	2,962,286	-	-	-	-	-	-
6.	Total Rate Base	$ 10,743,088	$ 8,502,167	$ (52,421)	$ (32,762)	$ 27,365	$ 37,625	$ 68,945	$ 172,449
	PRO FORMA WITNESS:			LOCKWOOD		LOCKWOOD		LOCKWOOD	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]			1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)		1. Jurisdictional 2. Distribution functionalized on Distribution and IT/Facilities functionalized on Wages & Salaries	

(1) Test Year Total Deductions and Total Additions are shown on Schedule B-1, page 1.

(2) Adjustment to Test Year rate base to include post-Test Year Plant Additions for Fossil Generation with an estimated in service date prior to 6/30/2020.

(3) Adjustment to Test Year rate base to include post-Test Year Plant Additions for Nuclear Generation with an estimated in service date prior to 6/30/2020.

(4) Adjustment to Test Year rate base to include post-' in service date prior to 6/30/2020.

(5) Adjustment to Test Year rate base to include post-' in service date prior to 6/30/2020.

(6) Adjustment to Test Year rate base to include post-' in service date prior to 6/30/2020.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

		(5)		(6)		(6a)			
		Technology Innovation Post-Test Year Plant Additions		Renewables Post-Test Year Plant Additions		Four Corners SCRs		Eliminate Capitalized Amount of Cash Incentive	
Line No.	Description	Total Co. (I)	ACC (J)	Total Co. (K)	ACC (L)	Total Co.	ACC	Total Co.	ACC
1.	Gross Utility Plant in Service	$ 14,187	$ 14,187	$ 17,048	$ 17,048	$ (478,802)	$ (476,216)	$ (8,031)	$ (8,031)
2.	Less: Accumulated Depreciation & Amo	-	-	33,094	33,094	$ (14,001)	$ (13,925)		
3	Net Utility Plant in Service	14,187	14,187	(16,046)	(16,046)	(464,801)	(462,290)	(8,031)	(8,031)
4.	Less: Total Deductions	433	433	2,183	2,183	(63,893)	$ (63,548)		
5.	Total Additions	-	-	635	635	-	-		
6.	Total Rate Base	$ 13,754	$ 24,669	$ (17,594)	$ (11,215)	$ (400,908)	$ (398,743)	$ (8,031)	$ (8,031)

	(5)	(6)
PRO FORMA WITNESS:	LOCKWOOD	LOCKWOOD
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Functionalized on Distribution	1. ACC Specific 2. Renewables functionalized on Demand Production (Retail DEMPROD1)

Test Year Plant Additions for Distribution and IT/Facilities with an estimated (7)

Test Year Plant Additions for Technology Innovation with an estimated (8)

Test Year Plant Additions for Renewables with an estimated (9)

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

		(7) Cloud Computing		(8) UPDATED FOR REBUTTAL Include West Phoenix Unit 4 Regulatory Disallowance		(9) UPDATED FOR REBUTTAL Include Property Tax Deferral		(10) UPDATED FOR REBUTTAL Adjust Cash Working Capital for Cost of Service	
Line No.	Description	Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)	Total Co. (S)	ACC (T)
1.	Gross Utility Plant in Service	$ -	$ -	$ (13,833)	$ (13,767) $ -	$ -	$ -	$ -	$ -
2.	Less: Accumulated Depreciation & Amo	-	-	(6,432)	(6,401)	-	-	-	-
3	Net Utility Plant in Service	-	-	(7,401)	(7,365)	-	-	-	-
4.	Less: Total Deductions	-	-	(1,514)	(1,507)	(2,551)	(2,551)	-	-
5.	Total Additions	12,779	11,731	-	-	(10,308)	(10,308)	(8,608)	(7,902)
6.	Total Rate Base	$ 12,779	$ 11,731	$ (5,887)	$ (5,859)	$ (7,757)	$ (7,757)	$ (8,608)	$ (7,902)

	(7)	(8)	(9)	(10)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. ACC Specific 2. Distribution Property Tax functionalized on Distribution and Generation Property Tax functionalized on Demand Production (Retail DEMPROD1)	1. Jurisdictional 2. Functionalized on Wages & Salaries

Adjustment to Test Year rate base to reflect the impacts of Cloud Computing in alignment with NARUC's Cloud Computing Resolution.

Adjustment to Test Year rate base to include the regulatory disallowance for West Phoenix CC Unit #4 as required by Decision Nos. 67744 and 69663.

Adjustment to Test Year rate base to include the deferred property tax amounts from 7/1/19 to 12/31/20 per Decision No. 76295.

(10) Adjustment to Cash Working Capital to reflect imp

(11) Adjustment to Test Year rate base to include the ε per Decision No. 76295.

(12) Adjustment to Test Year rate base to include the ε from 7/1/19 to 12/31/20 per Decision No. 76295.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

		(11) UPDATED FOR REBUTTAL Include Ocotillo Deferral		(12) UPDATED FOR REBUTTAL Include Four Corners SCR Deferral		12(a) UPDATED FOR REBUTTAL Reverse Four Corners SCR Deferral		(13) UPDATED FOR REBUTTAL Excess Deferred Tax	
Line No.	Description	Total Co. (U)	ACC (V)	Total Co. (W)	ACC (X)	Total Co.	ACC	Total Co. (Y)	ACC (Z)
1.	Gross Utility Plant in Service	$ -	$ -	$ -	$ -			$ -	$ -
2.	Less: Accumulated Depreciation & Amo	-	-	-	-			-	-
3	Net Utility Plant in Service	-	-	-	-			-	-
4.	Less: Total Deductions	21,180	21,180	10,779	10,779	(10,779)	(10,779)	(190,188)	(176,096)
5.	Total Additions	85,577	85,577	43,550	43,550	(43,550)	(43,550)	-	-
6.	Total Rate Base	$ 64,397	$ 64,397	$ 32,771	$ 32,771	$ (32,771)	$ (32,771)	$ 190,188	$ 176,096
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP				BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)				1. ACC Specific 2. Assigned to Production - Demand (Retail DEMPROD1)	

acts of cost of service pro formas on the lead/lag study.

stimated Ocotillo Modernization Project deferral amount from 7/1/19 to 12/31/20

stimated Four Corners Selective Catalytic Reduction (SCR) deferral amount

(13) Adjustment to rate base to reflect amortization of e
Test Year and the date proposed rates go into effe
Assumes TEAM III amortization begins 1/1/2020 ai

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

		(14) NEW FOR REBUTTAL TEAM Balancing Accounts		(15) NEW FOR REBUTTAL Remove McMicken		(16) UPDATED FOR REBUTTAL Total Original Cost Rate Base Pro Forma Adjustments		(17) Adjusted at End of Test Year 6/30/2019	
Line No.	Description	Total Co. (AA)	ACC (BB)	Total Co. (CC)	ACC (DD)	(b) Total Co. (EE)	(b) ACC (FF)	(b) Total Co. (CC)	(b) ACC (DD)
1.	Gross Utility Plant in Service	$ -	$ -			$ 93,784	$ 83,445	20,762,589	$ 17,605,599
2.	Less: Accumulated Depreciation & Amor	-	-	1,041	1,041	$ 519,699	$ 508,564	7,786,740	6,831,741
3	Net Utility Plant in Service	-	-	(1,041)	(1,041)	$ (425,915)	$ (425,119)	12,975,849	10,773,858
4.	Less: Total Deductions	-	-	-	-	$ (221,020)	$ (206,753)	5,562,488	5,659,096
5.	Total Additions	6,556	6,556	-	-	$ 86,631	$ 86,289	3,211,463	3,048,575
6.	Total Rate Base	$ 6,556	$ 6,556	$ (1,041)	$ (1,041)	$ (118,264)	$ (132,077)	$ 10,624,824	$ 8,163,337

PRO FORMA WITNESS:

PRO FORMA FUNCTIONALIZATION
or ALLOCATION FACTOR:
[WITNESS: SNOOK]

xcess deferred taxes associated with TEAM Phase III between the
ct.
d rates go into effect 1/1/2021.

Supporting Schedules
(a) B-1

Recap Schedules:
(b) B-1

NOTE: There may be variances in displyed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT
TOTAL COMPANY
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

		Total Company			
Line No.	Description	Actual For The Test Year Ended 6/30/2019 (a) (A)	Proforma Adjustments (b) (B)	Test Year Results After Proforma Adjustments (c) (C)	Line No.
	Operating Revenues:				
1.	Revenues from Base Rates	$ 3,284,386	$ 6,862	$ 3,291,248	1.
2.	Revenues from Surcharges	128,995	(113,995)	15,000	2.
3.	Other Electric Revenues	216,871	(6,040)	210,831	3.
4.	Total	3,630,252	(113,173)	3,517,079	4.
	Operating expenses:				
5.	Fuel and purchased power	1,094,682	(105,795)	988,887	5.
6.	Operations and maintenance	909,326	(221,510)	687,816	6.
7.	Depreciation and amortization	584,838	119,964	704,802	7.
8.	Income taxes	123,315	11,933	135,248	8.
9.	Taxes other than income taxes	215,143	(1,964)	213,179	9.
10.	Total	2,927,304	(197,372)	2,729,932	10.
11.	Operating income	702,948	84,199	787,147	11.
	Other income (deductions):				
12.	Income taxes	6,467	-	6,467	12.
13.	Allowance for equity funds used during construction	43,927	-	43,927	13.
14.	Other income	34,998	-	34,998	14.
15.	Other expense	(22,582)	-	(22,582)	15.
16.	Total	62,810	-	62,810	16.
17.	Income before interest deductions	765,758	84,199	849,957	17.
	Interest deductions (income):				
18.	Interest charges	227,758	-	227,758	18.
19.	Allowance for borrowed funds used during construction	(23,293)	-	(23,293)	19.
20.	Total	204,465	-	204,465	20.
21.	Net income	$ 561,293	$ 84,199	$ 645,492	21.

Supporting Schedules:
(a) E-2
(b) C-2

Recap Schedules:
(c) A-2

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT
ACC JURISDICTION
TEST YEAR ENDED JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	ACC Jurisdiction: Actual For The Test Year Ended 6/30/2019 (A)	Proforma Adjustments (a) (B)	Test Year Results After Proforma Adjustments (C)	Line No.
	Operating Revenues:				
1.	Revenues from Base Rates	$ 3,273,579	$ 6,862	$ 3,280,441	1.
2.	Revenues from Surcharges	128,979	(113,979)	15,000	2.
3.	Other Electric Revenues	148,270	(6,040)	142,230	3.
4.	Total	3,550,829	(113,157)	3,437,672	4.
	Operating expenses:				
5.	Fuel and purchased power	1,083,273	(105,527)	977,746	5.
6.	Operations and maintenance	1,052,961	(214,934)	838,027	6.
7.	Depreciation and amortization	511,942	118,782	630,724	7.
8.	Income taxes	113,517	15,606	129,123	8.
9.	Taxes other than income taxes	177,260	(2,424)	174,836	9.
10.	Total	2,938,954	(188,497)	2,750,457	10.
11.	Operating income	611,875	75,340	687,215 (b)	11.
	Other income (deductions):				
12.	Income taxes	-	-		12.
13.	Allowance for equity funds used during construction	-	-		13.
14.	Other income	-	-		14.
15.	Other expense	-	-		15.
16.	Total	-			16.
17.	Income before interest deductions	611,875	75,340	687,215	17.
	Interest deductions (income):				
18.	Interest charges	-	-		18.
19.	Allowance for borrowed funds used during construction	-	-		19.
20.	Total	-	-	-	20.
21.	Net income	$ 611,875	$ 75,340	$ 687,215	21.

Supporting Schedules:
(a) C-2

Recap Schedules:
(b) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(1) Fossil Generation Post-Test Year Plant Additions Total Co. (A)	(1) ACC (B)	(2) Nuclear Generation Post-Test Year Plant Additions Total Co. (C)	(2) ACC (D)	(3) Distribution and IT/Facilities Post-Test Year Plant Additions Total Co. (E)	(3) ACC (F)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	7,880	7,842	423	421	20,477	19,299
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	9,546	7,842	1,199	421	35,636	19,299
15.	Operating Income Before Income Tax	(9,546)	(7,842)	(1,199)	(421)	(35,636)	(19,299)
16.	Interest Expense	(410)	(408)	684	681	3,411	3,237
17.	Taxable Income	(9,136)	(7,434)	(1,883)	(1,101)	(39,047)	(22,536)
18.	Current Income Tax Rate - 24.75%	(2,261)	(1,840)	(466)	(273)	(9,664)	(5,578)
19.	Operating Income (line 15 minus line 18)	$ (7,285)	$ (6,002)	$ (733)	$ (148)	$ (25,972)	$ (13,721)

	(1)	(2)	(3)
PRO FORMA WITNESS:	LOCKWOOD	LOCKWOOD	LOCKWOOD
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Distribution facilities functionalized on Distribution and IT/Facilities functionalized on Wages & Salaries

(1) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Fossil Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 2.

(2) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Nuclear Generation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 1, column 3.

(3) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Distribution and IT/Facilities Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 4.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(4) Technology Innovation Post-Test Year Plant Additions Total Co. (G)	ACC (H)	(5) Renewables Post-Test Year Plant Additions Total Co. (I)	ACC (J)	(6) UPDATED FOR REBUTTAL Base Fuel and Purchased Power Total Co. (K)	ACC (L)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	(17,509)	(17,509)
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	17,509	17,509
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	1,419	1,419	648	648	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	3,025	1,419	1,023	648	-	-
15.	Operating Income Before Income Tax	(3,025)	(1,419)	(1,023)	(648)	17,509	17,509
16.	Interest Expense	473	473	(162)	(162)	-	-
17.	Taxable Income	(3,498)	(1,892)	(860)	(485)	17,509	17,509
18.	Current Income Tax Rate - 24.75%	(866)	(468)	(213)	(120)	4,333	4,333
19.	Operating Income (line 15 minus line 18)	$ (2,159)	$ (951)	$ (810)	$ (528)	$ 13,176	$ 13,176
	PRO FORMA WITNESS:	LOCKWOOD		LOCKWOOD		SNOOK	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Functionalize as Distribution.		1. ACC Specific 2. Renewables functionalized on Demand Production [Retail DEMPROD1]		1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2)	

(4) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Technology Innovation Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 5.

(5) Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Renewables Post-Test Year Plant Additions. Pro forma adjusted as shown on Schedule B-2, page 2, column 6.

(6) Adjustment to Test Year operations to include 2018 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

		(7)		(8)		(9)	
		Test Year PSA Revenue and Deferred Fuel Amortization		Test Year Retail Deferred Fuel Expense and Non-Cash Mark-to-Market Accruals		Test Year Deferred Chemical Expense	
Line No.	Description	Total Co. (M)	ACC (N)	Total Co. (O)	ACC (P)	Total Co. (Q)	ACC (R)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(89,285)	(89,040)	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(89,285)	(89,040)	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	(90,598)	(90,349)	40,435	40,435	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	1,313	1,309	(40,435)	(40,435)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	1,313	1,309	-	-	-	-
8.	Maintenance	-	-	-	-	3,194	3,194
9.	Subtotal	1,313	1,309	-	-	3,194	3,194
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	1,313	1,309	-	-	3,194	3,194
15.	Operating Income Before Income Tax	-	-	(40,435)	(40,435)	(3,194)	(3,194)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	-	-	(40,435)	(40,435)	(3,194)	(3,194)
18.	Current Income Tax Rate - 24.75%	-	-	(10,008)	(10,008)	(791)	(791)
19.	Operating Income (line 15 minus line 18)	$ -	$ -	$ (30,427)	$ (30,427)	$ (2,403)	$ (2,403)
	PRO FORMA WITNESS:	SNOOK		SNOOK		SNOOK	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Revenues and Expenses are class specific.		1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2_XAG1)		1. ACC Specific 2. Assigned to Production - Energy (Retail Only ENERGY2_XAG1)	

(7) Adjustment to Test Year retail operating revenues and fuel and purchased power expense to remove retail PSA revenue and amortization of deferred fuel related to prior periods.

(8) Adjustment to Test Year retail fuel and purchased power costs to remove retail PSA deferred fuel and mark-to-market accruals.

(9) Adjustment to Test Year operation and maintenance costs to remove retail PSA deferred chemical expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(10) Normalize Weather Conditions Total Co. (S)	(10) Normalize Weather Conditions ACC (T)	(11) Annualize Customer Levels Total Co. (U)	(11) Annualize Customer Levels ACC (V)	(12) Schedule 1 Fees Total Co. (W)	(12) Schedule 1 Fees ACC (X)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ (6,049)	$ (6,049)	$ 12,911	$ 12,911	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	(6,040)	(6,040)
4.	Total Electric Operating Revenues	(6,049)	(6,049)	12,911	12,911	(6,040)	(6,040)
5.	Electric Fuel and Purchased Power Costs	(1,812)	(1,812)	3,854	3,854	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(4,237)	(4,237)	9,057	9,057	(6,040)	(6,040)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	-	-	-	-
15.	Operating Income Before Income Tax	(4,237)	(4,237)	9,057	9,057	(6,040)	(6,040)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(4,237)	(4,237)	9,057	9,057	(6,040)	(6,040)
18.	Current Income Tax Rate - 24.75%	(1,049)	(1,049)	2,242	2,242	(1,495)	(1,495)
19.	Operating Income (line 15 minus line 18)	$ (3,188)	$ (3,188)	$ 6,815	$ 6,815	$ (4,545)	$ (4,545)
	PRO FORMA WITNESS:	SNOOK		SNOOK		HOBBICK	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Revenues and Expenses are class specific.		1. ACC Specific 2. Revenues and Expenses are class specific.		1. ACC Specific 2. Functionalized on Customer Accounts (CUSTNUM_A)	

(10) Adjustment to Test Year operating revenues to reflect normal weather conditions for the ten years ended 6/30/2019.

(11) Adjustment to Test Year operating revenues to reflect the annualization of customer levels at 6/30/2019.

(12) Adjustment to Test Year operations to account for additional adjustments related to disconnect policy.
Additional adjustments to Revenues reflecting policies changes to multiple fees collected.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

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Line No.	Description		(13) Uncollectible Bad Debt Total Co. (Y)	(13) Uncollectible Bad Debt ACC (Z)	(14) UPDATED FORREBUTTAL Crisis Bill Total Co. (AA)	(14) UPDATED FORREBUTTAL Crisis Bill ACC (AB)	(15) Customer Affordability Total Co. (AC)	(15) Customer Affordability ACC (AD)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		6,427	6,427	1,250	1,250	(17,782)	(17,782)
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		6,427	6,427	1,250	1,250	(17,782)	(17,782)
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		6,427	6,427	1,250	1,250	(17,782)	(17,782)
15.	Operating Income Before Income Tax		(6,427)	(6,427)	(1,250)	(1,250)	17,782	17,782
16.	Interest Expense		-	-	-	-	-	-
17.	Taxable Income		(6,427)	(6,427)	(1,250)	(1,250)	17,782	17,782
18.	Current Income Tax Rate -	24.75%	(1,591)	(1,591)	(309)	(309)	4,401	4,401
19.	Operating Income (line 15 minus line 18)		$ (4,836)	$ (4,836)	$ (941)	$ (941)	$ 13,381	$ 13,381
	PRO FORMA WITNESS:		HOBBICK		HOBBICK		LOCKWOOD	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]		1. ACC Specific 2. Functionalized on Customer Accounts (CUSTNUM_A)		1. ACC Specific 2. Assigned to System Benefits (Retail ERGSYSBEN)		1. ACC Specific 2. Functionalized on Wages & Salaries less Transmission	

(13) Adjustment to Test Year operations to account for expected increases in write-offs due to disconnect policy.

(14) Adjustment to Test Year operating revenues to reflect the increase need in crisis billing assistance.

(15) Adjustment to include forecasted impacts to 2020 O&M as a result of the Customer Affordability program.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

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			(16)		(17)		(18)	
			Active Union Medical Trust (VEBA)		Fire Mitigation		Remove Test Year Regulatory Assessment	
Line No.	Description		Total Co. (AE)	ACC (AF)	Total Co. (AG)	ACC (AH)	Total Co. (AI)	ACC (AJ)
	Electric Operating Revenues							
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	(6,769)	(6,769)
3.	Other Electric Revenues		-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	(6,769)	(6,769)
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	(6,769)	(6,769)
	Other Operating Expenses:							
7.	Operations Excluding Fuel Expense		(3,643)	(3,344)	3,298	3,298	(6,769)	(6,769)
8.	Maintenance		-	-	-	-	-	-
9.	Subtotal		(3,643)	(3,344)	3,298	3,298	(6,769)	(6,769)
10.	Depreciation and Amortization		-	-	-	-	-	-
11.	Amortization of Gain		-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-
14.	Total Other Operating Expense		(3,643)	(3,344)	3,298	3,298	(6,769)	(6,769)
15.	Operating Income Before Income Tax		3,643	3,344	(3,298)	(3,298)	-	-
16.	Interest Expense		-	-	-	-	-	-
17.	Taxable Income		3,643	3,344	(3,298)	(3,298)	-	-
18.	Current Income Tax Rate -	24.75%	902	828	(816)	(816)	-	-
19.	Operating Income (line 15 minus line 18)		$ 2,741	$ 2,516	$ (2,482)	$ (2,482)	$ -	$ -

	(16)	(17)	(18)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. ACC Specific 2. Functionalized on Distribution.	1. ACC Specific 2. Revenues are class specific and expenses are functionalized on Distribution of W&S

(16) Adjustment to Test Year operations to include interest income and realized gain on investments in active union medical trust.

(17) Adjustment to represent the forecasted impacts to 2020 O&M as a result of increases to the distribution Fire Mitigation program.

(18) Adjustment to Test Year operations to remove the Regulatory Assessment surcharges from operating revenues and expenses.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
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Line No.	Description	(19) Remove Test Year Transmission Cost Adjustor (TCA) Total Co. (AK)	(19) ACC (AL)	(20) Remove Test Year Lost Fixed Cost Recovery Mechanism (LFCR) Total Co. (AM)	(20) ACC (AN)	(21) Remove and Transfer Test Year Environmental Improvement Surcharge (EIS) Total Co. (AO)	(21) ACC (AP)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(33,311)	(33,369)	(39,792)	(39,792)	(3,898)	(3,888)
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(33,311)	(33,369)	(39,792)	(39,792)	(3,898)	(3,888)
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(33,311)	(33,369)	(39,792)	(39,792)	(3,898)	(3,888)
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(33,311)	(33,369)	(39,792)	(39,792)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(33,311)	(33,369)	(39,792)	(39,792)	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(33,311)	(33,369)	(39,792)	(39,792)	-	-
15.	Operating Income Before Income Tax	-	-	-	-	(3,898)	(3,888)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	-	-	-	-	(3,898)	(3,888)
18.	Current Income Tax Rate - 24.75%	-	-	-	-	(965)	(962)
19.	Operating Income (line 15 minus line 18)	$ -	$ -	$ -	$ -	$ (2,933)	$ (2,926)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Revenues are class specific		1. ACC Specific 2. Revenues are class specific		1. Jurisdictional 2. Revenues are class specific	

(19) Adjustment to Test Year operations to remove the Transmission Cost Adjustor from operating revenues and expenses.

(20) Adjustment to Test Year operations to remove the LFCR mechanism from operating revenues.

(21) Adjustment to Test Year operations to remove the EIS from operating revenues.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

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INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
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Line No.	Description	(22) Remove Test Year Demand Side Management Adjustment Clause (DSMAC) Revenue & Expense		(23) Remove Test Year and Transfer a Portion of Renewable Energy Adjustment Clause (REAC) Revenue and Expense		(24) Remove and Transfer Test Year Tax Expense Adjustor Mechanism (TEAM) Revenue	
		Total Co. (AQ)	ACC (AR)	Total Co. (AS)	ACC (AT)	Total Co. (AU)	ACC (AV)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	(26,717)	(26,689)	(72,697)	(72,670)	143,475	143,238
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	(26,717)	(26,689)	(72,697)	(72,670)	143,475	143,238
5.	Electric Fuel and Purchased Power Costs	-	-	(38,930)	(38,916)	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	(26,717)	(26,689)	(33,767)	(33,754)	143,475	143,238
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(26,717)	(26,689)	(33,445)	(33,433)	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	(26,717)	(26,689)	(33,445)	(33,433)		
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(26,717)	(26,689)	(33,445)	(33,433)	-	-
15.	Operating Income Before Income Tax	-	0	(322)	(321)	143,475	143,238
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	-	0	(322)	(321)	143,475	143,238
18.	Current Income Tax Rate - 24.75%	-	-	(80)	(80)	35,510	35,451
19.	Operating Income (line 15 minus line 18)	$ -	$ 0	$ (242)	$ (241)	$ 107,965	$ 107,787
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Revenues and Expenses are class specific.		1. Jurisdictional 2. Revenues and Expenses are class specific.		1. Jurisdictional 2. Revenues and Expenses are class specific.	

(22) Adjustment to Test Year operations to remove the DSMAC from operating revenues and expenses.

(23) Adjustment to Test Year operations to remove the REAC from operating revenues and transfer a portion of the expenses related to APS Solar Communities (formerly known as AZ Sun II) to base rates.

(24) Adjustment to Test Year operations to remove and transfer the TEAM adjustor from operating revenues.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

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INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
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			(25)		(25a)		(26)		(27)	
			UPDATED FOR REBUTTAL Four Corners SCR Deferral Amortization		Reverse Four Corners SCR Deferral Amortization		UPDATED FOR REBUTTAL Ocotillo Modernization Project Deferral Amortization		Four Corners Inventory	
Line No.	Description		Total Co. (AW)	ACC (AX)	Total Co. (AW)	ACC (AX)	Total Co. (AY)	ACC (AZ)	Total Co. (BA)	ACC (BB)
	Electric Operating Revenues									
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	-	-	-
3.	Other Electric Revenues		-	-	-	-	-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-	-	-	-	-
	Other Operating Expenses:									
7.	Operations Excluding Fuel Expense		8,147	8,147	(8,147)	(8,147)	9,507	9,507	-	-
8.	Maintenance		-	-	-	-	-	-	-	-
9.	Subtotal		8,147	8,147	(8,147)	(8,147)	9,507	9,507	-	-
10.	Depreciation and Amortization		8,147	8,147	(8,147)	(8,147)	9,507	9,507	1,045	1,040
11.	Amortization of Gain		-	-	-	-	-	-	-	-
12.	Administrative and General		-	-	-	-	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-	-	-
14.	Total Other Operating Expense		8,259	8,220	(16,294)	(16,294)	19,014	19,014	1,045	1,040
15.	Operating Income Before Income Tax		(8,259)	(8,220)	16,294	16,294	(19,014)	(19,014)	(1,045)	(1,040)
16.	Interest Expense		-	-	-	-	-	-	-	-
17.	Taxable Income		(8,259)	(8,220)	16,294	16,294	(19,014)	(19,014)	(1,045)	(1,040)
18.	Current Income Tax Rate -	24.75%	(2,044)	(2,034)	2,044	2,034	-	-	(259)	(257)
19.	Operating Income (line 15 minus line 18)		$ (6,215)	$ (6,186)	$ 14,250	$ 14,260	$ (19,014)	$ (19,014)	$ (786)	$ (783)

	(25)	(26)	(27)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)

(25) Adjustment to Test Year operations to include the amortization of the Four Corners SCR deferral.

(26) Adjustment to Test Year operations to include the amortization of the Ocotillo Modernization Project deferral.

(27) Adjustment to Test Year operations to reflect Four Corners inventory cost recovery.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

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Line No.	Description	(28) Cholla Inventory Total Co. (BC)	ACC (BD)	(29) West Phoenix Unit 4 Regulatory Disallowance Total Co. (BE)	ACC (BF)	(29a) Regulatory Asset Amortization Total Co.	ACC	ACC	(30) Remove Navajo Power Plant Costs Total Co. (BE)	ACC (BF)
	Electric Operating Revenues									
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -				$ -	$ -
2.	Revenues from Surcharges	-	-	-	-				-	-
3.	Other Electric Revenues	-	-	-	-				-	-
4.	Total Electric Operating Revenues	-	-	-	-				-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-				-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-				-	-
	Other Operating Expenses:									
7.	Operations Excluding Fuel Expense	-	-	-	-				(10,567)	(10,522)
8.	Maintenance	-	-	-	-				(6,446)	(6,418)
9.	Subtotal	-	-	-	-				(17,014)	(16,940)
10.	Depreciation and Amortization	1,523	1,516	(329)	(327)	80,000	80,000		-	-
11.	Amortization of Gain	-	-	-	-				-	-
12.	Administrative and General	-	-	-	-				541	539
13.	Other Taxes	-	-	-	-				-	-
14.	Total Other Operating Expense	1,523	1,516	(329)	(327)	80,000	80,000		(16,473)	(16,401)
15.	Operating Income Before Income Tax	(1,523)	(1,516)	329	327	(80,000)	(80,000)		16,473	16,401
16.	Interest Expense	-	-	(110)	(109)	-	-		-	-
17.	Taxable Income	(1,523)	(1,516)	439	437	(80,000)	(80,000)		16,473	16,401
18.	Current Income Tax Rate - 24.75%	(377)	(375)	109	108	(19,800)	(19,800)		4,077	4,059
19.	Operating Income (line 15 minus line 18)	$ (1,146)	$ (1,141)	$ 220	$ 219	$ (60,200)	$ (60,200)		$ 12,396	$ 12,342
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP					BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)		1. Jurisdictional 2. Assigned to Production - Demand (DEMPROD1)					1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)	

(28) Adjustment to Test Year operations to reflect Cholla inventory cost recovery.

(29) Adjustment to Test Year operations to reflect amortization of regulatory disallowance of West Phoenix Unit 4 over the remaining life of the plant as required by previous ACC Decision Nos. 67744 and 69663. Pro forma adjusted as shown on Schedule B-2, page 3, column 8.

(30) Adjustment to Test Year operations to remove Navajo O&M and A&G costs as a result of the closure of Navajo Power Plant.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

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Line No.	Description	(31) Ocotillo O&M Normalization Total Co. (BG)	(31) ACC (BH)	(32) UPDATED FOR REBUTTAL Include Interest Expense on Customer Deposits Total Co. (BI)	(32) ACC (BJ)	(33) UPDATED FOR REBUTTAL Adjust Depreciation Expense - 2019 Depreciation Rate Study Total Co. (BK)	(33) ACC (BL)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	5,643	5,618	1,270	1,270	-	-
8.	Maintenance	1,104	1,099	-	-	-	-
9.	Subtotal	6,747	6,717	1,270	1,270	-	-
10.	Depreciation and Amortization	-	-	-	-	7,483	7,483
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	(16)	(16)	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	6,730	6,701	1,270	1,270	7,483	7,483
15.	Operating Income Before Income Tax	(6,730)	(6,701)	(1,270)	(1,270)	(7,483)	(7,483)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	(6,730)	(6,701)	(1,270)	(1,270)	(7,483)	(7,483)
18.	Current Income Tax Rate - 24.75%	(1,666)	(1,659)	(314)	(314)	(1,852)	(1,852)
19.	Operating Income (line 15 minus line 18)	$ (5,064)	$ (5,042)	$ (956)	$ (956)	$ (5,631)	$ (5,631)

	(31)	(32)	(33)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)	1. ACC Specific 2. Assigned to Customer Accounts (CUSTDEP)	1. Jurisdictional 2. Assigned to PT&D, General and Intangible functionalized on Wages & Salaries

(31) Adjust Test Year to reflect the continuing operations of the Ocotillo Power Plant with the retirment of the 2 steam units and the addition of the new units.

(32) Adjustment to Test Year Operations to reflect the operating income impact of interest on customer deposits using January 2019 interest rates.

(33) Adjustment to Test Year operations to reflect depreciation expense based on the 2019 Depreciation Rate Study.

Supporting Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

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INCOME STATEMENT PRO FORMA ADJUSTMENTS
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(Thousands of Dollars)

Line No.	Description	(34) Annualize Payroll Expense Total Co. (BM)	(34) ACC (BN)	(35) UPDATED FOR REBUTTAL Normalize Employee Benefits Total Co. (BO)	(35) ACC (BP)	(36) Remove Supplemental Excess Benefit Retirement Plan Expense (SERP) Total Co. (BQ)	(36) ACC (BR)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(410)	(376)	(2,750)	(2,524)	(8,429)	(7,738)
8.	Maintenance	(84)	(77)	-	-	-	-
9.	Subtotal	(494)	(453)	(2,750)	(2,524)	(8,429)	(7,738)
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(494)	(453)	(2,750)	(2,524)	(8,429)	(7,738)
15.	Operating Income Before Income Tax	494	453	2,750	2,524	8,429	7,738
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	494	453	2,750	2,524	8,429	7,738
18.	Current Income Tax Rate - 24.75%	122	112	-	-	2,086	1,915
19.	Operating Income (line 15 minus line 18)	$ 372	$ 341	$ 2,750	$ 2,524	$ 6,343	$ 5,823

	(34)	(35)	(36)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. Jurisdictional 2. Functionalized on Wages & Salaries	1. Jurisdictional 2. Functionalized on Wages & Salaries

(34) Adjustment to Test Year operations to reflect the annualization of payroll, payroll tax and non-retirement benefit expenses to March 2019 employee levels for performance review and March 2020 Union employee levels.

(35) Adjustment to Test Year operations to reflect the current December 2018 actuarial valuation of retirement program expenses.

(36) Adjustment to Test Year operations to remove Supplemental Excess Benefit Retirement Plan Expense (SERP).

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(37) Remove Stock Compensation Total Co. (BS)	ACC (BT)	(38) Normalize Cash Incentive Total Co. (BU)	ACC (BV)	Reverse Normalization of Cash Incentive Total Co.	ACC	Cash Incentive -Allow 25% of Cash Incentive Total Co.	ACC	Executive Compensatio Base Salary Total Co.
	Electric Operating Revenues									
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
2.	Revenues from Surcharges	-	-	-	-	-	-	-	-	
3.	Other Electric Revenues	-	-	-	-	-	-	-	-	
4.	Total Electric Operating Revenues	-	-	-	-	-	-	-	-	
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-	-	-	
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-	-	-	
	Other Operating Expenses:									
7.	Operations Excluding Fuel Expense	(15,882)	(14,580)	4,153	3,812	(4,153)	(3,812)	(24,592)	(22,574)	(12,950)
8.	Maintenance	-	-	126	116	(126)	(116)	-	-	-
9.	Subtotal	(15,882)	(14,580)	4,279	3,928	(4,279)	(3,928)	(24,592)	(22,574)	(12,950)
10.	Depreciation and Amortization	-	-	-	-	-	-	-	-	
11.	Amortization of Gain	-	-	-	-	-	-	-	-	
12.	Administrative and General	-	-	1,327	1,218	(1,327)	(1,218)	-	-	
13.	Other Taxes	-	-	-	-	-	-	-	-	
14.	Total Other Operating Expense	(15,882)	(14,580)	5,606	5,146	(5,606)	(5,146)	(24,592)	(22,574)	(12,950)
15.	Operating Income Before Income Tax	15,882	14,580	(5,606)	(5,146)	5,606	5,146	24,592	22,574	12,950
16.	Interest Expense	-	-	-	-	-	-	-	-	-
17.	Taxable Income	15,882	14,580	(5,606)	(5,146)	5,606	5,146	24,592	22,574	12,950
18.	Current Income Tax Rate - 24.75%	3,931	3,608	(1,388)	(1,274)	1,388	1,274	6,086	5,587	3,205
19.	Operating Income (line 15 minus line 18)	$ 11,951	$ 10,972	$ (4,218)	$ (3,872)	$ 4,218	$ 3,872	$ 18,506	$ 16,987	$ 9,745
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP						
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Functionalized on Wages & Salaries						

(37) Adjustment to Test Year operations to remove stock compensation expense.

(38) Adjustment to Test Year operations to normalize the cash incentive program over a 3 year period.

(39) Adjustment to Test Year operations for top down income tax true-ups consistent with Decision Nos. 69663, 71448, 73183, and 76295 using the 6/30/2019 rate base and cost of long-term debt. Tax true-ups are reflected as interest in this adjustment.

Supporting Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

(39)

Line No.	Description		n - Remove 50% of	D&E Insurance 50/50 Sharing		EEI and Other Membership Dues - 50/50 Sharing		Normalize Income Tax Expense/Interest Synchronization	
			ACC	Total Co.	ACC	Total Co.	ACC	Total Co. (BW)	ACC (BX)
	Electric Operating Revenues								
1.	Revenues from Base Rates			$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges			-	-	-	-	-	-
3.	Other Electric Revenues			-	-	-	-	-	-
4.	Total Electric Operating Revenues			-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs			-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs			-	-	-	-	-	-
	Other Operating Expenses:								
7.	Operations Excluding Fuel Expense		(12,173)	-	-	-	-	-	-
8.	Maintenance		-	-	-	-	-	-	-
9.	Subtotal		(12,173)	-	-	-	-	-	-
10.	Depreciation and Amortization			-	-	-	-	-	-
11.	Amortization of Gain			-	-	-	-	-	-
12.	Administrative and General			(376)	(376)	(1,791)	(1,791)	-	-
13.	Other Taxes			-	-	-	-	-	-
14.	Total Other Operating Expense		(12,173)	(376)	(376)	(1,791)	(1,791)	-	-
15.	Operating Income Before Income Tax		12,173	376	376	1,791	1,791	-	-
16.	Interest Expense		-	-	-	-	-	23,665	24,404
17.	Taxable Income		12,173	376	376	1,791	1,791	(23,665)	(24,404)
18.	Current Income Tax Rate -	24.75%	3,013	93	93	443	443	(5,857)	$ (6,040)
19.	Operating Income (line 15 minus line 18)		$ 9,160	$ 283	$ 283	$ 1,348	$ 1,348	$ 5,857	$ 6,040

PRO FORMA WITNESS: BLANKENSHIP

PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]

1. Jurisdictional
2. Calculated as the weighted average of "Other Tax Items"

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

		(40)		(41)		(42)	
		UPDATED FOR REBUTTAL Annualize Property Tax Expense		UPDATED FOR REBUTTAL Amortize Property Tax Deferral		West Phoenix Removal Costs	
Line No.	Description	Total Co. (BY)	ACC (BZ)	Total Co. (CA)	ACC (CB)	Total Co. (CC)	ACC (CD)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	998	993
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	2,750	2,290	(4,671)	(4,671)	-	-
14.	Total Other Operating Expense	2,750	2,290	(4,671)	(4,671)	998	993
15.	Operating Income Before Income Tax	(2,750)	(2,290)	4,671	4,671	(998)	(993)
16.	Interest Expense	-	-	(151)	(151)	-	-
17.	Taxable Income	(2,750)	(2,290)	4,822	4,822	(998)	(993)
18.	Current Income Tax Rate - 24.75%	-	-	-	-	(247)	(246)
19.	Operating Income (line 15 minus line 18)	$ (2,750)	$ (2,290)	$ 4,671	$ 4,671	$ (751)	$ (747)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Functionalized on P T & D		ACC Specific 2. Distribution Property Tax functionalized on Distribution and Generation Property Tax functionalized on Demand Production (Retail DEMPROD1)		1. Jurisdictional 2. Assigned to Production Demand (DEMPROD1)	

(40) Adjustment to Test Year operations to annualize property taxes calculated using the anticipated 2019 tax assessment ratio and tax rate.

(41) Adjustment to amortize the property tax deferral as authorized in Decision No. 76295 over 10 years. Pro forma adjusted as shown on Schedule B-2, page 3, column 9.

(42) Adjustment to include additional costs of removal related to the decommissioning of West Phoenix Steam Units 4, 5 & 6.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

		(43)		(44)		(45)	
		Annualize Four Corners Power Plant Coal Reclamation Costs		Annualize Navajo Power Plant Coal Reclamation Costs		UPDATED FOR REBUTTAL Adjust Cash Working Capital for Cost of Service Pro Formas	
Line No.	Description	Total Co. (CE)	ACC (CF)	Total Co. (CG)	ACC (CH)	Total Co. (CI)	ACC (CJ)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	(3,145)	(3,131)	1,910	1,902	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	3,145	3,131	(1,910)	(1,902)	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-
8.	Maintenance	-	-	-	-	-	-
9.	Subtotal	-	-	-	-	-	-
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	-	-	-	-	-	-
15.	Operating Income Before Income Tax	3,145	3,131	(1,910)	(1,902)	-	-
16.	Interest Expense	-	-	-	-	(160)	(147)
17.	Taxable Income	3,145	3,131	(1,910)	(1,902)	160	147
18.	Current Income Tax Rate - 24.75%	778	775	(473)	(471)	-	-
19.	Operating Income (line 15 minus line 18)	$ 2,367	$ 2,356	$ (1,437)	$ (1,431)	$ -	$ -
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN)		1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN)		1. Jurisdictional 2. Functionalized on Wages & Salaries	

(43) Adjustment to Test Year operations to reflect most recent Four Corners Power Plant coal reclamation study.

(44) Adjustment to Test Year operations to reflect the most recent Navajo Power Plant coal reclamation study.

(45) Adjustment to Test Year interest expense for cash working capital rate base pro forma adjustment.
Pro forma adjusted as shown on Schedule B-2, page 4, column 10.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(46) Normalize Advertising Total Co. (CK)	(46) Normalize Advertising ACC (CL)	(47) Normalize Nuclear Maintenance Expense Total Co. (CM)	(47) Normalize Nuclear Maintenance Expense ACC (CN)	(48) Normalize Fossil Maintenance Expense Total Co. (CO)	(48) Normalize Fossil Maintenance Expense ACC (CP)
	Electric Operating Revenues						
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-	-	-
3.	Other Electric Revenues	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-
	Other Operating Expenses:						
7.	Operations Excluding Fuel Expense	(2,264)	(2,264)	-	-	-	-
8.	Maintenance	-	-	1,386	1,380	5,882	5,856
9.	Subtotal	(2,264)	(2,264)	1,386	1,380	5,882	5,856
10.	Depreciation and Amortization	-	-	-	-	-	-
11.	Amortization of Gain	-	-	-	-	-	-
12.	Administrative and General	-	-	-	-	-	-
13.	Other Taxes	-	-	-	-	-	-
14.	Total Other Operating Expense	(2,264)	(2,264)	1,386	1,380	5,882	5,856
15.	Operating Income Before Income Tax	2,264	2,264	(1,386)	(1,380)	(5,882)	(5,856)
16.	Interest Expense	-	-	-	-	-	-
17.	Taxable Income	2,264	2,264	(1,386)	(1,380)	(5,882)	(5,856)
18.	Current Income Tax Rate - 24.75%	560	560	(343)	(342)	(1,456)	(1,449)
19.	Operating Income (line 15 minus line 18)	$ 1,704	$ 1,704	$ (1,043)	$ (1,038)	$ (4,426)	$ (4,407)
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Functionalized on Wages & Salaries less Transmission		1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)		1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)	

(46) Adjustment to Test Year operations to normalize advertising expense over a 3 year period.

(47) Adjustment to Test Year operations to normalize nuclear production maintenance expense over a 3 year period.

(48) Adjustment to Test Year operations to normalize fossil production maintenance expense over a 6 year period.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(49) Adjust Sundance Maintenance Total Co. (CQ)	(49) ACC (CR)	(50) UPDATED FOR REBUTTAL Remove Out of Period and Miscellaneous Items Total Co. (CS)	(50) ACC (CT)	(51) Cholla Unit 2 Regulatory Asset Amortization Total Co. (CS)	(51) ACC (CT)	(52) NEW FOR REBUTTAL Adjust for Test Year AG-X Revenue recovered in the PSA Total Co. (CW)	(52) ACC (CX)
	Electric Operating Revenues								
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-	-	15,000	15,000
3.	Other Electric Revenues		-	-	-	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-	-	-	15,000	15,000
5.	Electric Fuel and Purchased Power Costs		-	-	-	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-	-	-	15,000	15,000
	Other Operating Expenses:								
7.	Operations Excluding Fuel Expense	-	-	-	-	-	-	-	-
8.	Maintenance	1,487	1,481	-	-	-	-	-	-
9.	Subtotal	1,487	1,481	-	-	-	-	-	-
10.	Depreciation and Amortization		-	-	-	(11,504)	(11,454)	-	-
11.	Amortization of Gain		-	-	-	-	-	-	-
12.	Administrative and General		-	(15,136)	(13,894)	-	-	-	-
13.	Other Taxes		-	-	-	-	-	-	-
14.	Total Other Operating Expense	1,487	1,481	(15,136)	(13,894)	(11,504)	(11,454)	-	-
15.	Operating Income Before Income Tax	(1,487)	(1,481)	15,136	13,894	11,504	11,454	15,000	15,000
16.	Interest Expense		-	-	-	-	-	-	-
17.	Taxable Income	(1,487)	(1,481)	15,136	13,894	11,504	11,454	15,000	15,000
18.	Current Income Tax Rate - 24.75%	(368)	(366)	-	-	2,847	2,835	3,713	3,713
19.	Operating Income (line 15 minus line 18)	$ (1,119)	$ (1,115)	$ 15,136	$ 13,894	$ 8,657	$ 8,619	$ 11,287	$ 11,287
	PRO FORMA WITNESS:	BLANKENSHIP		BLANKENSHIP		BLANKENSHIP		SNOOK	
	PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. Jurisdictional 2. Assigned to Production - Energy (ENERGY1)		1. Jurisdictional 2. Functionalized on Wages & Salaries		1. Jurisdictional 2. Assigned to System Benefits (ERGSYSBEN)		1. ACC Specific 2. Revenues and Expenses are class specific	

(49) Adjustment to Test Year operations to annualize the accrual of Sundance maintenance costs as authorized in Decision No. 69663.

(50) Adjustment to Test Year operations to remove out of period and miscellaneous items from the Test Year period.

(51) Adjust test year to amortize Cholla Unit 2 Regulatory Asset over the remaining plant life instead of the accelerated method approved in Decision No. 76295.

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

Line No.	Description	(53) NEW FOR REBUTTAL TEAM Balancing Account Total Co. (CY)	ACC (CZ)	(54) NEW FOR REBUTTAL Remove McMicken Total Co. (DA)	ACC (DB)
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ -	$ -	$ -	$ -
2.	Revenues from Surcharges	-	-	-	-
3.	Other Electric Revenues	-	-	-	-
4.	Total Electric Operating Revenues	-	-	-	-
5.	Electric Fuel and Purchased Power Costs	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-	-
	Other Operating Expenses:				
7.	Operations Excluding Fuel Expense	-	-	-	-
8.	Maintenance	-	-	-	-
9.	Subtotal	-	-	-	-
10.	Depreciation and Amortization	656	656	(261)	(261)
11.	Amortization of Gain	-	-	-	-
12.	Administrative and General	-	-	(659)	(659)
13.	Other Taxes	-	-	(43)	(43)
14.	Total Other Operating Expense	656	656	(963)	(963)
15.	Operating Income Before Income Tax	(656)	(656)	963	963
16.	Interest Expense	-	-	(19)	(19)
17.	Taxable Income	(656)	(656)	982	982
18.	Current Income Tax Rate - 24.75%	(162)	(162)	243	243
19.	Operating Income (line 15 minus line 18)	$ (494)	$ (494)	$ 720	$ 720

	(53)	(54)
PRO FORMA WITNESS:	BLANKENSHIP	BLANKENSHIP
PRO FORMA FUNCTIONALIZATION or ALLOCATION FACTOR: [WITNESS: SNOOK]	1. ACC Specific 2. Assigned to Production Demand (DEMPROD1)	1. ACC Specific 2. Functionalized on Distribution

Supporting Schedules:
N/A

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED
JUNE 30, 2019
(Thousands of Dollars)

(52)

Line No.	Description		Total Income Statement Adjustments (a) Total Co. (CU)	(a) ACC (CV)
	Electric Operating Revenues			
1.	Revenues from Base Rates		$ 6,862	$ 6,862
2.	Revenues from Surcharges		$ (113,995)	$ (113,979)
3.	Other Electric Revenues		(6,040)	(6,040)
4.	Total Electric Operating Revenues		(113,173)	(113,157)
5.	Electric Fuel and Purchased Power Costs		(105,795)	$ (105,527)
6.	Oper Rev Less Fuel & Purch Pwr Costs		(7,378)	(7,630)
	Other Operating Expenses:			
7.	Operations Excluding Fuel Expense		$ (210,596)	$ (205,251)
8.	Maintenance		6,523	6,515
9.	Subtotal		(204,073)	(198,736)
10.	Depreciation and Amortization		$ 119,964	$ 118,782
11.	Amortization of Gain		$ -	$ -
12.	Administrative and General		$ (17,437)	$ (16,198)
13.	Other Taxes		(1,964)	(2,424)
14.	Total Other Operating Expense		(103,510)	(98,576)
15.	Operating Income Before Income Tax		96,132	90,946
16.	Interest Expense		$ 27,221	$ 27,798
17.	Taxable Income		68,911	63,148
18.	Current Income Tax Rate -	24.75%	$ 11,933	$ 15,606
19.	Operating Income (line 15 minus line 18)		$ 84,199	$ 75,340

PRO FORMA WITNESS:

PRO FORMA FUNCTIONALIZATION
or ALLOCATION FACTOR:
[WITNESS: SNOOK]

Supporting Schedules:
N/A

Recap Schedules:
(a) C-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDING JUNE 30, 2019 ADJUSTED

Line No.	Customer Classification	Base Revenues in the Test Year (a) (A) Present Rates [1,2] ($000)	(B) Proposed Rates [2] ($000)	Proposed Increase (b) (C) Change ($000) (B) - (A)	(D) % (C) / (A)	(E) Adjustor Transfers [3] ($000)	(F) Net Change ($000) (C) - (E)	(G) Net Increase [4] % (F) / (A)	Line No.
1.	Residential	1,740,264	1,652,386	(87,878)	-5.05%	55,268	(32,610)	-1.87%	1.
2.	General Service	1,476,858	1,391,368	(85,490)	-5.79%	57,816	(27,674)	-1.87%	2.
3.	Irrigation/Water Pumping	32,188	30,211	(1,977)	-6.14%	1,374	(603)	-1.87%	3.
4.	Outdoor Lighting	20,814	20,017	(797)	-3.83%	407	(390)	-1.87%	4.
5.	Dusk to Dawn Lighting Service	9,067	8,720	(347)	-3.83%	177	(170)	-1.87%	5.
6.	Total Sales to Ultimate Retail Customers	3,279,191	3,102,702	(176,489)	-5.38%	115,042	(61,447)	-1.87%	6.

NOTES TO SCHEDULE:

1) Base Revenues under Present Rates reflect adjusted Test Year revenues including applicable proforma adjustments.
2) Present and Proposed Rates base revenues include transmission costs based on OATT rates effective during Test Year.
3) Includes revenue from Test Year adjustor rates that are being transferred into base rates.
4) Increase in base rates net of transfers of adjustor revenue. Represents the net increase in retail revenue and net impact on customers.

Supporting Schedules:
(a) H-2

Recap Schedules:
(b) A-1

NOTE: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDING JUNE 30, 2019 ADJUSTED

Line No.	(A) Customer Classification and Current Rate Designation	(B) Average Number of Customers	(C) Adjusted MWh [2] Sales	(D) Average Annual kWh Usage per Customer	(E) Base Revenues under Present Rates [1] ($000)	(F) Proposed Rate Designation	(G) Proposed Revenue: Base Revenues ($000)	(H) Proposed Revenue: Change - Base Rates ($000) (G) - (E)	(I) Proposed Revenue: Change - Base Rates % (H) / (E)	(J) Net Increase With Adjustor Transfers ($000)	(K) % (J) / (E)	Adjustor Transfers ($)	Line No.
1	Residential												1
2	R-XS	262,514	1,440,066	5,486	199,012	R-XS	188,962	(10,050)	-5.05%	(3,730)	-1.87%	(6,320)	2
3	R-BASIC	128,349	1,044,218	8,136	147,263	R-BASIC	139,826	(7,437)	-5.05%	(2,760)	-1.87%	(4,677)	3
4	R-BASIC L	45,514	587,679	12,912	86,348	R-BASIC L	81,987	(4,361)	-5.05%	(1,619)	-1.87%	(2,742)	4
5	TOU-E	376,890	5,284,626	14,022	731,481	TOU-E	694,541	(36,940)	-5.05%	(13,709)	-1.87%	(23,231)	5
6	R-2	62,729	1,018,356	16,234	134,124	R-2	127,351	(6,773)	-5.05%	(2,513)	-1.87%	(4,260)	6
7	R-3	159,772	3,304,742	20,684	385,902	R-3	366,414	(19,488)	-5.05%	(7,232)	-1.87%	(12,256)	7
8	R-TECH	18	582	32,333	79	R-TECH	75	(4)	-5.05%	(1)	-1.25%	(3)	8
9	Subtotal	1,035,786	12,680,269	12,242	1,684,209	Subtotal	1,599,156	(85,053)	-5.05%	(31,564)	-1.87%	(53,489)	9
10	E-12 Solar Legacy	29,487	76,647	2,599	13,608	E-12 Solar Legacy	12,921	(687)	-5.05%	(255)	-1.88%	(432)	10
11	ET-1 Solar Legacy	8,970	53,880	6,007	6,863	ET-1 Solar Legacy	6,516	(347)	-5.05%	(129)	-1.87%	(218)	11
12	ET-2 Solar Legacy	34,009	239,203	7,034	29,609	ET-2 Solar Legacy	28,114	(1,495)	-5.05%	(555)	-1.88%	(940)	12
13	ECT-2 Solar Legacy	2,964	27,398	9,244	4,889	ECT-2 Solar Legacy	4,642	(247)	-5.05%	(92)	-1.88%	(155)	13
14	ECT-1R Solar Legacy	557	6,482	11,637	1,086	ECT-1R Solar Legacy	1,031	(55)	-5.05%	(21)	-1.92%	(34)	14
15	Subtotal	75,987	403,610	5,312	56,055	Subtotal	53,224	(2,831)	-5.05%	(1,052)	-1.88%	(1,779)	15
16	Total Residential	1,111,773	13,083,879	11,768	1,740,264	Total Residential	1,652,381	(87,883)	-5.05%	(32,615)	-1.87%	(55,268)	16

NOTES: There may be variances in displayes values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDING JUNE 30, 2019 ADJUSTED

Line No.	(A) Customer Classification and Current Rate Designation	(B) Average Number of Customers	(C) Adjusted MWh [2] Sales	(D) Average Annual kWh Usage per Customer	(E) Base Revenues under Present Rates [1] ($000)	(F) Proposed Rate Designation	(G) Proposed Revenue: Base Revenues ($000)	(H) Proposed Revenue: Change - Base Rates ($000) (G) - (E)	(I) Proposed Revenue: % (H) / (E)	(J) Net Increase With Adjustor Transfers ($000)	(K) % (J) / (E)	Adjustor Transfers ($)	Line No.
17	<u>General Service</u>												17
18	E-20	398	36,368	91,377	4,548	E-20	4,285	(263)	-5.79%	(114)	-2.51%	(149)	18
19	E-30	4,327	4,838	1,118	1,279	E-30	1,205	(74)	-5.79%	(35)	-2.74%	(39)	19
20	E-32 XS	100,521	1,572,444	15,643	235,725	E-32 XS	222,077	(13,648)	-5.79%	(6,505)	-2.76%	(7,143)	20
21	E-32 XS D	395	8,594	21,757	1,377	E-32 XS D	1,297	(80)	-5.79%	(38)	-2.74%	(42)	21
22	E-32 S	19,307	2,529,103	130,994	321,655	E-32 S	303,031	(18,624)	-5.79%	(8,877)	-2.76%	(9,747)	22
23	E-32 M	4,221	3,172,447	751,587	341,611	E-32 M (includes AG-X)	321,733	(19,878)	-5.79%	(6,569)	-1.91%	(13,309)	23
24	E-32 M (AG-X)	14	24,253	1,732,357	1,699		-						24
25	E-32 L	826	2,862,403	3,465,379	267,658	E-32 L (includes AG-X)	250,397	(17,261)	-5.79%	(3,847)	-1.29%	(13,414)	25
26	E-32 L (AG-X)	92	387,756	4,214,739	30,463		-						26
27	E-32TOU XS	282	9,207	32,649	1,396	E-32TOU XS	1,315	(81)	-5.79%	(39)	-2.78%	(42)	27
28	E-32TOU S	155	29,527	190,497	3,776	E-32TOU S	3,557	(219)	-5.79%	(105)	-2.77%	(114)	28
29	E-32TOU M	73	79,258	1,085,726	7,842	E-32TOU M	7,388	(454)	-5.79%	(150)	-1.91%	(304)	29
30	E-32TOU L	61	301,031	4,934,934	26,092	E-32TOU L (includes AG-X)	24,508	(1,584)	-5.79%	(357)	-1.31%	(1,227)	30
31	E-32 TOU L (AG-X)	1	5,752	5,752,000	1,266		-						31
32	E-34	20	626,469	31,323,450	49,303	(E-34, E-35, XHLF, AG-X)	37,209	(12,094)	-5.79%	(410)	-0.20%	(11,684)	32
33	E-34 (AG-X)	2	66,487	33,243,500	4,474		-						33
34	E-35	30	1,109,193	36,973,100	88,438		-						34
35	E-35 (AG-X)	7	671,702	95,957,429	40,596		-						35
36	XHLF	1	430,145	430,145,000	26,066		-						36
37	E-36 M	26	8,447	324,885	896	E-36 M	-	(52)	-5.79%	(52)	-5.79%	-	37
38	GS-S M	174	94,062	540,586	13,446	GS-S M	12,667	(779)	-5.79%	(388)	-2.88%	(391)	38
39	GS-S L	53	59,803	1,128,358	7,252	GS-S L	6,832	(420)	-5.79%	(209)	-2.88%	(211)	39
40	Subtotal	130,986	14,089,289	107,563	1,476,858	Subtotal	1,197,502	(85,510)	-5.79%	(27,694)	-1.88%	(57,816)	40

NOTES: There may be variances in displayes values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY
SUMMARY OF BASE REVENUES BY CUSTOMER CLASSIFICATION
PRESENT AND PROPOSED RATES
TEST YEAR ENDING JUNE 30, 2019 ADJUSTED

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)		
							Proposed Revenue						
Line No.	Customer Classification and Current Rate Designation	Average Number of Customers	Adjusted MWh [2] Sales	Average Annual kWh Usage per Customer	Base Revenues under Present Rates[1] ($000)	Proposed Rate Designation	Base Revenues ($000)	Change - Base Rates ($000)	%	Net Increase With Adjustor Transfers ($000)	%	Adjustor Transfers ($)	Line No.
								(G) - (E)	(H) / (E)		(J) / (E)		
41	Irrigation	1,408	321,857	228,592	32,188	Irrigation	30,212	(1,976)	-6.14%	(602)	-1.87%	(1,374)	41
42	Outdoor Lighting												42
43	E-58	775	27,988	36,114	9,863	E-58	9,485	(378)	-3.83%	(185)	-1.87%	(193)	43
44	E-59	375	76,805	204,813	9,164	E-59	8,813	(351)	-3.83%	(172)	-1.88%	(179)	44
45	E-67	155	8,074	52,090	441	E-67	424	(17)	-3.83%	(8)	-1.79%	(9)	45
46	Contract 12	43	14,388	334,605	1,346	Contract 12	1,294	(52)	-3.83%	(26)	-1.90%	(26)	46
47	Subtotal	1,348	127,255	94,403	20,814	Subtotal	20,017	(797)	-3.83%	(390)	-1.87%	(407)	47
48	Dusk to Dawn Lighting[3]		21,954		9,067	Dusk to Dawn Lighting[3]	8,720	(347)	-3.83%	(170)	-1.88%	(177)	48
49	Total Retail	1,245,515	27,644,234	22,195	3,279,191		2,908,831	(176,514)	-5.38%	(61,472)	-1.87%	(115,042)	49

1. Base Revenues under Present Rates reflect adjusted Test Year revenues based on rates established in Decision No. 76295.
2. MWh and sales excludes revenue credits. MWh with revenue credits = 27,764,053.
3. Dusk to Dawn Lighting customers are included in residential and general service counts as this service is included on each customer's primary billing.

Additional Notes
Rider rate schedules are included in the "Parent" rate schedules listed on schedule H-2 as applicable.
Riders include: E-3, E-4, CPP-RES, PPR, CPP-GS, GPS-1, GPS-2, GPS-3, E-56, E-56 R, IRR, SD-1, and SGSP.
Rate Schedule E-36 is not included as proposed price changes are market-related.
Transmission revenues based on OATT charges effective during Test Year.

Supporting Schedules:
N/A

Recap Schedules:
(a) H-1

NOTES: There may be variances in displayes values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Year Ending June 30, 2019

	(A)	(B)	(C)	(D)	(E)		(F)	(G)	(H)		(I)	(J)	(K)	(L)	
Line No.	Rate Schedule	Description	Billing Designation	Season	Present Rates Block		Rates		Proposed Rates Block		Rates			Change (I) - (F)	Line No.
1	E-3	Residential Energy	Rate	Sum & Win	per bill discount		25%	disc.	per bill discount		25%	disc.		-	1
2		Support Program													2
3															3
4															4
5															5
6	E-4	Medical Care	Rate	Sum & Win	per bill discount		35%	disc.	per bill discount		35%	disc.		-	6
7		Equipment													7
8		Support Program													8
9															9
10	E-3 Legacy	Residential Energy	Rate	Sum & Win	0 kWh to 400 kWh		65%	per bill	0 kWh to 400 kWh		65%	per bill		-	10
11		Support Program			401 kWh to 800 kWh		45%	per bill	401 kWh to 800 kWh		45%	per bill		-	11
12					801 kWh to 1,200 kWh		26%	per bill	801 kWh to 1,200 kWh		26%	per bill		-	12
13					1,201 kWh and above	$	31.75	per bill	1,201 kWh and above	$	31.75	per bill		-	13
14															14
15	E-4 Legacy	Medical Care	Rate	Sum & Win	0 kWh to 800 kWh		65%	per bill	0 kWh to 800 kWh		65%	per bill		-	15
16		Equipment			801 kWh to 1,400 kWh		45%	per bill	801 kWh to 1,400 kWh		45%	per bill		-	16
17		Support Program			1,401 kWh to 2,000 kWh		26%	per bill	1,401 kWh to 2,000 kWh		26%	per bill		-	17
18					2,001 kWh and above	$	60.00	per bill	2,001 kWh and above	$	60.00	per bill		-	18
19															19
20	R-XS	Residential Service	Rate	Sum & Win	Basic Service Charge	$	0.329	/day	Basic Service Charge	$	0.329	/day	$	-	20
21		Annual monthly usage less than			All kWh		0.11672	/kWh	All kWh		0.11083	/kWh		(0.00589)	21
22		or equal to 600 kWh													22
23															23
24	R-Basic	Residential Service	Rate	Sum & Win	Basic Service Charge	$	0.493	/day	Basic Service Charge	$	0.493	/day	$	-	24
25		Annual monthly usage of more			All kWh		0.12393	/kWh	All kWh		0.11767	/kWh		(0.00626)	25
26		than 600 but less than 1,000 kwh													26
27															27
28	R-Basic Large	Residential Service	Rate	Sum & Win	Basic Service Charge	$	0.658	/day	Basic Service Charge	$	0.658	/day	$	-	28
29		Annual monthly usage of 1000			All kWh		0.13412	/kWh	All kWh		0.12735	/kWh		(0.00677)	29
30		or more													30
31															31
32	TOU-E	Residential Service	Rate	Summer	Basic Service Charge	$	0.427	/day	Basic Service Charge	$	0.427	/day	$	-	32
33		Time of Use			All On-Peak kWh		0.24314	/kWh	All On-Peak kWh		0.23086	/kWh		(0.01228)	33
34					All Off-Peak kWh		0.10873	/kWh	All Off-Peak kWh		0.10324	/kWh		(0.00549)	34
35															35
36				Winter											36
37					Basic Service Charge	$	0.427	/day	Basic Service Charge	$	0.427	/day	$	-	37
38					All On-Peak kWh		0.23068	/kWh	All On-Peak kWh		0.21903	/kWh		(0.01165)	38
39					All Off-Peak kWh		0.10873	/kWh	All Off-Peak kWh		0.10324	/kWh		(0.00549)	39
40					All Super Off-Peak kWh		0.03200	/kWh	All Super Off-Peak kWh		0.03200	/kWh		-	40
41															41
42				Sum & Win	All kW-dc of generation (Grid Access Charge)	$	0.930	/kW-dc	All kW-dc of generation (Grid Access Charge)		0.88304	/kW-dc		(0.04697)	42
43															43
44	R-2	Residential Service	Rate	Summer	Basic Service Charge	$	0.427	/day	Basic Service Charge	$	0.427	/day	$	-	44
45		Time of Use with			All On-Peak kW		8.400	/kW	All On-Peak kW		7.976	/kW		(0.42420)	45
46		Demand Charge			All On-Peak kWh		0.13160	/kWh	All On-Peak kWh		0.12495	/kWh		(0.00665)	46
47					All Off-Peak kWh		0.07798	/kWh	All Off-Peak kWh		0.07404	/kWh		(0.00394)	47
48				Winter											48
49					Basic Service Charge	$	0.427	/day	Basic Service Charge	$	0.427	/day	$	-	49
50					All On-Peak kW		8.400	/kW	All On-Peak kW		7.976	/kW		(0.424)	50
51					All On-Peak kWh		0.11017	/kWh	All On-Peak kWh		0.10461	/kWh		(0.00556)	51
52					All Off-Peak kWh		0.07798	/kWh	Off-Peak kWh		0.07404	/kWh		(0.00394)	52
53									Super Off-Peak		0.03294	/kWh		0.03294	53
54															54
55	R-3	Residential Service	Rate	Summer	Basic Service Charge	$	0.427	/day	Basic Service Charge	$	0.427	/day	$	-	55
56		Time of Use with			All On-Peak kW		17.438	/kW	All On-Peak kW		16.557	/kW		(0.881)	56
57		Demand Charge			All On-Peak kWh		0.08683	/kWh	All On-Peak kWh		0.08245	/kWh		(0.00438)	57
58					All Off-Peak kWh		0.05230	/kWh	All Off-Peak kWh		0.04966	/kWh		(0.00264)	58
59				Winter											59
60					Basic Service Charge	$	0.427	/day	Basic Service Charge	$	0.427	/day	$	-	60
61					All On-Peak kW		12.239	/kW	All On-Peak kW		11.621	/kW		(0.618)	61
62					All On-Peak kWh		0.06376	/kWh	All On-Peak kWh		0.06054	/kWh		(0.00322)	62
63					All Off-Peak kWh		0.05230	/kWh	Off-Peak kWh		0.04966	/kWh		(0.00264)	63
64									Super Off-Peak		0.03294	/kWh		0.03294	64

Supporting Schedules:
N/A

Recap Schedules:
N/A

Note: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Year Ending June 30, 2019

Line No.	(A) Rate Schedule	(B) Description	(C) Billing Designation	(D) Season	(E) Present Rates Block		(F) Present Rates	(G)	(H) Proposed Rates Block		(I) Proposed Rates	(J)	(K)	(L) Change (I) - (F)	Line No.
65															65
66	R-Tech	Residential Service	Rate	Summer	Basic Service Charge	$	0.493	/day	Basic Service Charge	$	0.493	/day	$	-	66
67		Time of Use with			All On-Peak kW		20.250	/kW	All On-Peak kW		19.227	/kW		(1.023)	67
68		Demand Charge			Off-Peak first 5 kW		-	/kW	Off-Peak first 5 kW		-	/kW		-	68
69					Off-Peak all remaining kW		6.500	/kW	Off-Peak all remaining kW		6.172	/kW		(0.328)	69
70					All On-Peak kWh		0.05750	/kWh	All On-Peak kWh		0.05460	/kWh		(0.00290)	70
71					All Off-Peak kWh		0.04750	/kWh	All Off-Peak kWh		0.04510	/kWh		(0.00240)	71
72															72
73			Rate	Winter	Basic Service Charge	$	0.493	/day	Basic Service Charge	$	0.493	/day	$	-	73
74					All On-Peak kW		14.250	/kW	All On-Peak kW		13.530	/kW		(0.720)	74
75					Off-Peak first 5 kW		-	/kW	Off-Peak first 5 kW		-	/kW		-	75
76					Off-Peak all remaining kW		6.500	/kW	Off-Peak all remaining kW		6.172	/kW		(0.328)	76
77					All On-Peak kWh		0.04750	/kWh	All On-Peak kWh		0.04510	/kWh		(0.00240)	77
78					Off-Peak kWh		0.04750	/kWh	Off-Peak kWh		0.04510	/kWh		(0.00240)	78
79															79
80															80
81	E-12	Residential Service	Rate	Summer	Basic Service Charge	$	0.330	/day	Basic Service Charge	$	0.330	/day	$	-	81
82	Solar Legacy				First 400 kWh		0.11161	/kWh	First 400 kWh		0.10597	/kWh		(0.00564)	82
83					Next 400 kWh		0.15920	/kWh	Next 400 kWh		0.15116	/kWh		(0.00804)	83
84					Next 2200 kWh		0.18627	/kWh	Next 2200 kWh		0.17686	/kWh		(0.00941)	84
85					All additional kWh		0.19863	/kWh	All additional kWh		0.18860	/kWh		(0.01003)	85
86															86
87				Winter	Basic Service Charge	$	0.330	/day	Basic Service Charge	$	0.330	/day	$	-	87
88					All kWh		0.10851	/kWh	All kWh		0.10303	/kWh		(0.00548)	88
89															89
90	ET-1	Residential Service	Rate	Summer	Basic Service Charge	$	0.643	/day	Basic Service Charge	$	0.643	/day	$	-	90
91	Solar Legacy	Time of Use			All On-Peak kWh		0.20697	/kWh	All On-Peak kWh		0.19652	/kWh		(0.01045)	91
92					All Off-Peak kWh		0.06697	/kWh	All Off-Peak kWh		0.06359	/kWh		(0.00338)	92
93															93
94				Winter	Basic Service Charge	$	0.643	/day	Basic Service Charge	$	0.643	/day	$	-	94
95					All On-Peak kWh		0.16794	/kWh	All On-Peak kWh		0.15946	/kWh		(0.00848)	95
96					All Off-Peak kWh		0.06397	/kWh	All Off-Peak kWh		0.06074	/kWh		(0.00323)	96
97															97
98	ET-2	Residential Service	Rate	Summer	Basic Service Charge	$	0.643	/day	Basic Service Charge	$	0.643	/day	$	-	98
99	Solar Legacy	Time of Use			All On-Peak kWh		0.28205	/kWh	All On-Peak kWh		0.26781	/kWh		(0.01424)	99
100					All Off-Peak kWh		0.07105	/kWh	All Off-Peak kWh		0.06746	/kWh		(0.00359)	100
101															101
102				Winter	Basic Service Charge	$	0.643	/day	Basic Service Charge	$	0.643	/day	$	-	102
103					All On-Peak kWh		0.22900	/kWh	All On-Peak kWh		0.21744	/kWh		(0.01156)	103
104					All Off-Peak kWh		0.07005	/kWh	All Off-Peak kWh		0.06651	/kWh		(0.00354)	104
105															105
106	ECT-1R	Residential Service	Rate	Summer	Basic Service Charge	$	0.643	/day	Basic Service Charge	$	0.643	/day	$	-	106
107	Solar Legacy	Time of Use with			All On-Peak kW		15.691	/kW	All On-Peak kW		14.899	/kW		(0.792)	107
108		Demand Charge			All On-Peak kWh		0.08490	/kWh	All On-Peak kWh		0.08061	/kWh		(0.00429)	108
109					All Off-Peak kWh		0.04730	/kWh	All Off-Peak kWh		0.04491	/kWh		(0.00239)	109
110															110
111				Winter	Basic Service Charge	$	0.643	/day	Basic Service Charge	$	0.643	/day	$	-	111
112					All On-Peak kW		10.885	/kW	All On-Peak kW		10.335	/kW		(0.550)	112
113					All On-Peak kWh		0.06470	/kWh	All On-Peak kWh		0.06143	/kWh		(0.00327)	113
114					All Off-Peak kWh		0.04594	/kWh	All Off-Peak kWh		0.04362	/kWh		(0.00232)	114
115															115
116	ECT-2	Residential Service	Rate	Summer	Basic Service Charge	$	0.643	/day	Basic Service Charge	$	0.643	/day	$	-	116
117	Solar Legacy	Time of Use with			All On-Peak kW		15.614	/kW	All On-Peak kW		14.825	/kW		(0.789)	117
118		Demand Charge			All On-Peak kWh		0.10256	/kWh	All On-Peak kWh		0.09738	/kWh		(0.00518)	118
119					All Off-Peak kWh		0.05109	/kWh	All Off-Peak kWh		0.04851	/kWh		(0.00258)	119
120															120
121				Winter	Basic Service Charge	$	0.643	/day	Basic Service Charge	$	0.643	/day	$	-	121
122					All On-Peak kW		10.756	/kW	All On-Peak kW		10.213	/kW		(0.543)	122
123					All On-Peak kWh		0.06647	/kWh	All On-Peak kWh		0.06311	/kWh		(0.00336)	123
124					All Off-Peak kWh		0.04750	/kWh	All Off-Peak kWh		0.04510	/kWh		(0.00240)	124
125															125
126	CPP-RES	Residential Service	Rate	Summer	Critical Peak Price	$	0.25000	/kWh	Critical Peak Price	$	0.25000	/kWh	$	-	126
127		Critical Peak Pricing			Energy Discount		(0.012143)	/kWh	Energy Discount		(0.01153)	/kWh		0.00	127

Supporting Schedules:
N/A

Recap Schedules:
N/A

Note: There may be variances in displayed values due to rounding.

ARIZONA PUBLIC SERVICE COMPANY

CHANGES IN REPRESENTATIVE RATE SCHEDULES
COMPARISON OF PRESENT AND PROPOSED RATES

Year Ending June 30, 2019

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	
					Present Rates			Proposed Rates					
Line No.	Rate Schedule	Description	Billing Designation	Season	Block	Rates		Block	Rates		Change (I) - (F)		Line No.
128													128
129	E-20	General Service	Rate	Summer	Basic Service Charge	$ 2.020	/day	Basic Service Charge	$ 2.020	/day	$ -		129
130		Time of Use for			All On-Peak kW	3.800	/kW	All On-Peak kW	3.608	/kW	(0.192)		130
131		Religious Houses of			Excess Off-Peak kW	2.400	/kW	Excess Off-Peak kW	2.279	/kW	(0.121)		131
132		Worship			All On-Peak kWh	0.15474	/kWh	All On-Peak kWh	0.14693	/kWh	(0.00781)		132
133					All Off-Peak kWh	0.07535	/kWh	All Off-Peak kWh	0.07154	/kWh	(0.00381)		133
134													134
135			Rate	Winter	Basic Service Charge	$ 2.020	/day	Basic Service Charge	$ 2.020	/day	$ -		135
136					All On-Peak kW	3.800	/kW	All On-Peak kW	3.608	/kW	(0.192)		136
137					Excess Off-Peak kW	2.400	/kW	Excess Off-Peak kW	2.279	/kW	(0.121)		137
138					All On-Peak kWh	0.13642	/kWh	All On-Peak kWh	0.12953	/kWh	(0.00689)		138
139					All Off-Peak kWh	0.06764	/kWh	All Off-Peak kWh	0.06422	/kWh	(0.00342)		139
140													140

Supporting Schedules:
N/A

Recap Schedules:
N/A

Note: There may be variances in displayed values due to rounding.

SCHEDULES

Arizona Public Service Company
Test Year Ended June 30, 2019
Docket No. E-01345A-19-0236

RUCO PROPOSED
CAPITAL STRUCTURE & WEIGHTED AVERAGE COST OF CAPITAL
($ thousands of dollars)

Line No	Description	[A] Company proposed Capital Structure	[B] RUCO Adjustments	[C] RUCO Adjusted Capital Structure	[D] Capital Ratio	[E] Cost Rate	[F] Weighted Cost
1	Long-Term Debt	$ 4,726,125	$ -	$ 4,726,125	45.33%	4.10%	1.86%
2							
3	Common Equity	5,700,968	$ -	$ 5,700,968	54.67%	8.70%	4.76%
4	TOTAL CAPITALIZATION	$ 10,427,093	$ -	$ 10,427,093	100.00%		**6.62%**

[A] : Company Schedule D-1
[B] : RUCO Adjustments
[C] : [A] + [B]
[D] : Capital ratio based on values shown in Column [C].
[E] : Company Schedule D-1, and RUCO Schedule JAC-2.
[F] : [D] * [E]

Arizona Public Service Company
Cost of Capital Calculation
Fair Value Rate Base (FVRB),
Fair Value Rate of Return (FVROR) and
Cost Rate to be Assigned to the Fair Value Increment
RUCO Recommended
($ in thousands)

Calculation of RUCO Fair Value Rate Base (FVRB)

Line No.		Rate Base Estimate		Amount	Weighting		Weighted Amount
1	[1]	Original Cost Rate Base (OCRB) - RUCO Recommended	$	8,261,698	50%	$	4,130,849
2	[2]	RUCO Reconstruction Cost New (RCND) Rate Base	$	15,136,256	50%		7,568,128
3		**Fair Value Rate Base (FVRB)**				**$**	**11,698,977**
4		Appreciation above OCRB				$	3,437,279
5		FV/OCRB Multiple		1.42			

Calculation of RUCO Fair Value Rate of Return (FVROR)

Line No.	Capital		Amount	Percent	Cost Rate	Weighted Cost
6	Long-Term Debt	$	3,744,650	32.01%	4.10%	1.3123%
7	Common Equity	$	4,517,048	38.61%	8.70%	3.3601%
8	Capital Financing OCRB	$	8,261,698			
9	Fair Value Increment	$	3,437,279	29.38%	0.00%	0.00%
10	**Fair Value Rate of Return**	$	11,698,977	100.00%		**4.67%**

Calculation of Cost Rate to be Assigned to the Fair Value Increment

Line No.		Cost Inputs	Cost Rate
11	[3]	Nominal Risk-Free Rate - Forecasted	1.75%
12	[4]	Less: CPI Inflation Component - Forecasted	1.30%
13		Real Risk-Free Rate	0.45%
14		**Cost Rate - Fair Value Increment**	0.45%
15		**RUCO RECOMMENDED COST RATE - Fair Value Increment**	**0.00%**

Sources:
[1] Frank Radigan Direct, Exhibit FWR-2 (RUCO Schedule A-1)
[2] Frank Radigan Direct, Exhibit FWR-2 (RUCO Schedule A-1)
[3] Nominal risk-free rate is the yield on the 30-year U.S. Treasury Bond, forecasted one year out to Q3 - 2021.
https://tradingeconomics.com/forecast/government-bond-10y
[4] Consumer Price Index (CPI) inflation, forecasted one year out to Q4 - 2021.
https://data.oecd.org/price/inflation-forecast.htm

Arizona Public Service Company
Test Year Ended June 30, 2019
Docket No. E-01345A-19-0236

Cost of Common Equity

Line No.			Common Equity Cost Rate: Indicated Cost of Common Equity	Weight Factor	Indicated Weighted Cost
1	Discounted Cash Flow Model ("DCF")	Schedule JAC - 3	8.63%	40.00%	3.4526%
2	Capital Asset Pricing Model ("CAPM")	Schedule JAC - 4	7.75%	20.00%	1.5500%
3	Comparable Earnings Model ("CE")	Schedule JAC - 5	9.75%	40.00%	3.9000%
4	Sample Average Indicated Cost of Common Equity		8.71%		
5	**RUCO Indicated Weighted Cost of Common Equity**				**8.90%**
6	RUCO Proposed Downward Adjustment				0.20%
7	**RUCO Recommended Cost of Common Equity**				**8.70%**

[Lines 1 - 3]: From Schedules JAC-3, JAC-4 and JAC-5
[Lines 4 - 5]: See Testimony
[Line 6]: See Direct Testimony of Jordy Fuentes
[Line 7]: See Testimony

PROXY GROUP -- DIVIDEND YIELD

Line No	Proxy Group Companies	Ticker	(A) DPS	(B) August 2020 - October 2020 High	(C) Low	(D) Average	(E) Yield
1	Allete, Inc.	ALE	$2.47	$61.32	$49.91	$55.62	4.44%
2	Ameren Corporation	AEE	$1.98	$85.43	$75.27	$80.35	2.46%
3	American Electric Power Company, Inc.	AEP	$2.80	$94.21	$77.30	$85.76	3.27%
4	DTE Energy Company	DTE	$4.05	$130.89	$109.65	$120.27	3.37%
5	Duke Energy Corporation	DUK	$3.86	$94.37	$78.95	$86.66	4.45%
6	Exelon Corporation	EXC	$1.53	$42.77	$33.97	$38.37	3.99%
7	Evergy, Inc.	EVRG	$2.02	$65.39	$48.61	$57.00	3.54%
8	OGE Energy Corporation	OGE	$1.55	$34.10	$28.25	$31.18	4.97%
9	Otter Tail Corporation	OTTR	$1.48	$42.02	$35.36	$38.69	3.83%
10	PNM Resources, Inc.	PNM	$1.23	$50.25	$39.00	$44.63	2.76%
11	Southern Company	SO	$2.56	$61.26	$51.22	$56.24	4.55%
12	Xcel Energy Inc.	XEL	$1.72	$74.41	$65.69	$70.05	2.46%
13	Average						**3.67370%**

References:

Column (A) - *Value Line Investment Survey*, Ratings & Reports (September 11, October 23, and November 13, 2020).

DPS reflects annualization of most recent quarterly dividend.

Columns (B), (C), and (D) - Yahoo Finance

http://finance.yahoo.com

PROXY GROUP -- PER SHARE GROWTH RATES

Line No	Proxy Group Companies	Ticker	5-Year Compound Average Annual Historical Growth, 2015-2019				5-Year Compound Average Annual Projected Growth, 2020-2024			
			EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
1	Allete, Inc.	ALE	4.0%	3.5%	5.0%	4.2%	4.5%	4.5%	3.5%	4.2%
2	Ameren Corporation	AEE	6.5%	3.0%	2.5%	4.0%	6.0%	5.0%	6.0%	5.7%
3	American Electric Power Company	AEP	4.0%	5.5%	3.0%	4.2%	5.0%	5.5%	4.5%	5.0%
4	DTE Energy Company	DTE	7.5%	7.0%	5.0%	6.5%	6.0%	6.5%	5.5%	6.0%
5	Duke Energy Corporation	DUK	2.5%	3.0%	1.0%	2.2%	5.0%	2.5%	2.5%	3.3%
6	Exelon Corporation	EXC	4.5%	NMF	4.0%	4.3%	3.5%	5.5%	3.5%	4.2%
7	Evergy, Inc.	EVRG	NMF	NMF	NMF	NMF	4.5%	5.5%	2.0%	4.0%
8	OGE Energy Corporation	OGE	2.0%	10.0%	5.5%	5.8%	3.0%	6.0%	0.5%	3.2%
9	Otter Tail Corporation	OTTR	9.0%	2.5%	4.5%	5.3%	3.5%	5.0%	4.0%	4.2%
10	PNM Resources, Inc.	PNM	7.0%	10.0%	NMF	8.5%	7.5%	6.5%	6.0%	6.7%
11	Southern Company	SO	3.0%	3.5%	3.0%	3.2%	3.0%	3.0%	3.5%	3.2%
12	Xcel Energy Inc.	XEL	5.0%	6.5%	4.5%	5.3%	6.0%	6.0%	5.5%	5.8%
13	Average					4.86%				4.61%

Reference:
Value Line Investment Survey, Ratings & Reports (various issues - September 11, October 23, and November 13, 2020).

PROXY GROUP -- GROWTH RATES RETAINED TO COMMON EQUITY

Line No	Proxy Group Companies	Ticker	(A) 2015	(B) 2016	(C) 2017	(D) 2018	(E) 2019	Average	2020	2021	2023-'25	Average
1	Allete, Inc.	ALE	3.6%	2.8%	2.4%	2.7%	2.3%	2.8%	1.5%	2.0%	2.5%	2.0%
2	Ameren Corporation	AEE	2.5%	3.3%	3.4%	4.8%	4.4%	3.7%	4.0%	4.0%	4.5%	4.2%
3	American Electric Power Company	AEP	3.9%	5.5%	3.2%	3.5%	3.4%	3.9%	3.5%	3.5%	3.5%	3.5%
4	DTE Energy Company	DTE	3.4%	3.7%	4.6%	4.9%	4.1%	4.1%	4.0%	4.0%	4.5%	4.2%
5	Duke Energy Corporation	DUK	1.5%	0.6%	1.2%	1.0%	2.4%	1.3%	2.0%	2.0%	2.5%	2.2%
6	Exelon Corporation	EXC	4.5%	1.9%	4.7%	2.2%	4.7%	3.6%	4.0%	4.0%	4.0%	4.0%
7	Evergy, Inc.	EVRG				0.6%	2.4%	1.5%	2.0%	2.5%	2.5%	2.3%
8	OGE Energy Corporation	OGE	4.0%	3.3%	3.5%	3.8%	3.6%	3.6%	3.0%	3.0%	2.5%	2.8%
9	Otter Tail Corporation	OTTR	2.0%	2.1%	3.3%	4.0%	4.0%	3.1%	3.0%	3.0%	3.5%	3.2%
10	PNM Resources, Inc.	PNM	3.3%	2.8%	4.5%	2.9%	5.4%	3.8%	3.5%	4.0%	4.5%	4.0%
11	Southern Company	SO	3.1%	2.5%	3.9%	2.6%	2.8%	3.0%	2.5%	2.5%	3.0%	2.7%
12	Xcel Energy Inc.	XEL	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	3.5%	4.0%	4.0%	3.8%
13	Average							3.22%				3.24%

Source: *Value Line Investment Survey*, Ratings & Reports (various issues - September 11, October 23, and November 13, 2020).

PROXY GROUP -- DCF ANALYSIS

Line No	Proxy Group Companies	Ticker	(A) Current Dividend Yield (D_0/P_0)	(B) Historic Retention Growth	(C) Projected Retention Growth	(D) Historical Per Share Growth Rates	(E) Projected Per Share Growth Rates	(F) Yahoo! Fin. Projected 5-Year EPS Growth	(G) Average Growth	(H) Expected Dividend Yield (D_1/P_0)	(I) DCF Rates
1	Allete, Inc.	ALE	4.4%	2.8%	2.0%	4.2%	4.2%	7.00%	4.0%	4.5%	8.5%
2	Ameren Corporation	AEE	2.5%	3.7%	4.2%	4.0%	5.7%	3.50%	4.2%	2.5%	6.7%
3	American Electric Power Company	AEP	3.3%	3.9%	3.5%	4.2%	5.0%	5.50%	4.4%	3.3%	7.8%
4	DTE Energy Company	DTE	3.4%	4.1%	4.2%	6.5%	6.0%	6.03%	5.4%	3.5%	8.8%
5	Duke Energy Corporation	DUK	4.5%	1.3%	2.2%	2.2%	3.3%	2.31%	2.3%	4.5%	6.8%
6	Exelon Corporation	EXC	4.0%	3.6%	4.0%	4.3%	4.2%	NMF	4.0%	4.1%	8.1%
7	Evergy, Inc.	EVRG	3.5%	1.5%	2.3%	NMF	4.0%	6.00%	3.5%	3.6%	7.1%
8	OGE Energy Corporation	OGE	5.0%	3.6%	2.8%	5.8%	3.2%	2.40%	3.6%	5.1%	8.6%
9	Otter Tail Corporation	OTTR	3.8%	3.1%	3.2%	5.3%	4.2%	9.00%	4.9%	3.9%	8.9%
10	PNM Resources, Inc.	PNM	2.8%	3.8%	4.0%	8.5%	6.7%	3.98%	5.4%	2.8%	8.2%
11	Southern Company	SO	4.6%	3.0%	2.7%	3.2%	3.2%	4.53%	3.3%	4.6%	7.9%
12	Xcel Energy Inc.	XEL	2.5%	4.2%	3.8%	5.3%	5.8%	6.20%	5.1%	2.5%	7.6%
13	Mean		3.67%	3.22%	3.24%	4.86%	4.61%	5.13%	4.17%	3.75%	7.92%
14	Median		3.68%	3.62%	3.33%	4.25%	4.17%	5.50%	4.11%	3.76%	8.00%
15	Composite-Mean			6.96%	6.98%	8.60%	8.36%	8.88%	7.92%		
16	Composite-Median			7.38%	7.10%	8.01%	7.93%	9.26%	7.87%		

References:
Column [A] : Schedule JAC - 3 (Page 1)
Column [B] : Schedule JAC - 3, page 4 of 4
Column [C] : Schedule JAC - 3, page 4 of 4
Column [D] and Column [E] : Schedule JAC - 3, page 2 of 4
Column [F] : See Yahoo Finance, Growth Estimates - Next 5 Years - See Attachment 7 (Downloaded November 17, 2020)
Column [G] : Average Columns [B] through [F]
Column [H] : Column [A] * (1 + (Column [G]* (0.5)))
Column [I] : Column [G] + Column [H]
Note: Low and high values for each base (mean / composite mean, and median / composite median) are highlighted.
NMF: Not Meaningful Figure

CAPITAL ASSET PRICING MODEL -- PROXY COMPANY COST RATES

Line No	Proxy Group Companies	Ticker	[A] Risk Free Rate	[B] BETA	[C] Risk Premium	[D] [B] * [C]	[E] CAPM Rates
1	Allete, Inc.	ALE	1.23%	0.85	7.40%	6.29%	7.51%
2	Ameren Corporation	AEE	1.23%	0.80	7.40%	5.92%	7.14%
3	American Electric Power Company	AEP	1.23%	0.75	7.40%	5.55%	6.78%
4	DTE Energy Company	DTE	1.23%	0.90	7.40%	6.66%	7.88%
5	Duke Energy Corporation	DUK	1.23%	0.85	7.40%	6.29%	7.51%
6	Exelon Corporation	EXC	1.23%	0.95	7.40%	7.03%	8.25%
7	Evergy, Inc.	EVRG	1.23%	1.00	7.40%	7.40%	8.62%
8	OGE Energy Corporation	OGE	1.23%	1.05	7.40%	7.77%	8.99%
9	Otter Tail Corporation	OTTR	1.23%	0.85	7.40%	6.29%	7.51%
10	PNM Resources, Inc.	PNM	1.23%	0.95	7.40%	7.03%	8.25%
11	Southern Company	SO	1.23%	0.90	7.40%	6.66%	7.88%
12	Xcel Energy Inc.	XEL	1.23%	0.80	7.40%	5.92%	7.14%
13	Average			0.8875			7.80%
14	Median						7.70%
	20 year Treasury Bonds						
15	August 2020		1.14%				
16	September 2020		1.21%				
17	October 2020		1.34%				
18	Average		1.23%				
19	RUCO Risk-Free Rate			1.23%			

REFERENCES

Column [A]: United States Treasury Department - Attachment 2
https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2019

Column [B]: *Value Line Investment Survey*, *Ratings & Reports* (September 11, October 23,and November 13, 2020 -- See Attachment 1)
Note: Updated beta coefficients for PNM and XEL obtained from *Value Line Investment Survey*, *Summary & Index* (Sept. 11, 2020).

Column [C]: JAC - 4, Page 2 of 2

Column [D]: [B] * [C]

Column [E]: [A] + [D]

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Line No.	Year	[A] EPS	[B] BVPS	[C] ROE	[D] 20-YEAR T-BOND	[E] RISK PREMIUM
1	1977		$79.07			
2	1978	$12.33	$85.35	15.00%	7.90%	7.10%
3	1979	$14.86	$94.27	16.55%	8.86%	7.69%
4	1980	$14.82	$102.48	15.06%	9.97%	5.09%
5	1981	$15.36	$109.43	14.50%	11.55%	2.95%
6	1982	$12.64	$112.46	11.39%	13.50%	-2.11%
7	1983	$14.03	$116.93	12.23%	10.38%	1.85%
8	1984	$16.64	$122.47	13.90%	11.74%	2.16%
9	1985	$14.61	$125.20	11.80%	11.25%	0.55%
10	1986	$14.48	$126.82	11.49%	8.98%	2.51%
11	1987	$17.50	$134.07	13.42%	7.92%	5.50%
12	1988	$23.75	$141.32	17.25%	8.97%	8.28%
13	1989	$22.87	$147.26	15.85%	8.81%	7.04%
14	1990	$21.73	$153.01	14.47%	8.19%	6.28%
15	1991	$16.29	$158.85	10.45%	8.22%	2.23%
16	1992	$18.86	$149.74	12.22%	7.26%	4.96%
17	1993	$21.89	$180.88	13.24%	7.17%	6.07%
18	1994	$30.60	$193.06	16.37%	6.59%	9.78%
19	1995	$33.96	$216.51	16.58%	7.60%	8.98%
20	1996	$38.73	$237.08	17.08%	6.18%	10.90%
21	1997	$39.72	$249.52	16.33%	6.64%	9.69%
22	1998	$37.71	$266.40	14.62%	5.83%	8.79%
23	1999	$48.17	$290.68	17.29%	5.57%	11.72%
24	2000	$50.00	$325.80	16.22%	6.50%	9.72%
25	2001	$24.70	$338.37	7.44%	5.53%	1.91%
26	2002	$27.59	$321.72	8.36%	5.59%	2.77%
27	2003	$48.73	$367.17	14.15%	4.80%	9.35%
28	2004	$58.55	$414.75	14.98%	5.02%	9.96%
29	2005	$69.93	$453.06	16.12%	4.69%	11.43%
30	2006	$81.51	$504.39	17.03%	4.68%	12.35%
31	2007	$66.18	$529.59	12.80%	4.86%	7.94%
32	2008	$14.88	$451.37	3.03%	4.45%	-1.42%
33	2009	$50.97	$513.58	10.56%	3.47%	7.09%
34	2010	$77.35	$579.14	14.16%	4.25%	9.91%
35	2011	$86.95	$613.14	14.59%	3.82%	10.77%
36	2012	$86.51	$666.97	13.52%	2.46%	11.06%
37	2013	$100.20	$715.84	14.49%	2.88%	11.61%
38	2014	$102.31	$726.96	14.18%	3.41%	10.77%
39	2015	$86.53	$740.29	11.79%	2.55%	9.24%
40	2016	$94.55	$768.98	12.53%	2.30%	10.23%
41	2017	$109.88	$807.04	13.94%	2.65%	11.29%
42	2018	$132.39	$841.26	16.06%	3.11%	12.95%
43	2019	$139.47	$892.65	16.09%	2.40%	13.69%
44	Average			**13.79%**	**6.39%**	**7.40%**

[A]: Diluted earnings per share on the S&P 500 Composite Index.
[B]: Book value per share on the S&P 500 Composite Index.
[C]: Average of current- and prior year [B] / current year [A].
[D]: Annual income returns on 20-year U.S. Treasury bonds.
[E]: [C] - [D]

Sources for [A] and [B]: Standard & Poor's 2015 Analysts' Handbook and
Standard & Poor's 500 Earnings and Book Value Per Share:
https://ycharts.com/indicators/reports/sp_500_earnings
https://ycharts.com/indicators/sandp_500_book_value_per_share
Source for [D]: Morningstar 2015 Classic Yearbook (Table A-7) and
U.S. Department of the Treasury
https://www.treasury.gov/Pages/default.aspx

COMPARABLE EARNINGS ANALYSIS

RETURN ON COMMON EQUITY FOR RUCO'S PROXY GROUP OF COMPANIES

		Historical ROEs										Projected ROEs			10-Year Historical Average	5-Year Historical Average	5-Year Projected Average	5-Yr Combined Historical & Projected Average
Company	Ticker	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2023 - 2025	2010-2019	2015-2019	2020-2024	
Allete, Inc.	ALE	7.7%	8.7%	8.1%	7.8%	7.8%	9.0%	8.2%	7.7%	8.1%	7.7%	6.5%	7.5%	8.0%	8.1%	8.1%	7.3%	7.7%
Ameren Corporation	AEE	8.6%	7.5%	8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.5%	10.0%	10.0%	8.9%	9.6%	9.8%	9.7%
American Electric Power Company	AEP	9.1%	10.3%	9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.5%	10.0%	10.5%	10.0%	10.4%	10.3%	10.4%
DTE Energy Company	DTE	9.4%	8.9%	9.0%	8.3%	10.9%	9.1%	9.6%	10.8%	10.9%	10.0%	10.5%	10.5%	11.0%	9.7%	10.1%	10.7%	10.4%
Duke Energy Corporation	DUK	7.8%	8.1%	5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	6.7%	8.3%	8.0%	8.5%	8.5%	7.1%	7.1%	8.3%	7.7%
Exelon Corporation	EXC	18.9%	17.3%	7.3%	8.7%	8.0%	8.8%	6.5%	8.8%	6.5%	9.1%	8.5%	8.5%	8.5%	10.0%	7.9%	8.5%	8.2%
Evergy, Inc.	EVRG									5.3%	7.8%	7.0%	8.0%	8.5%	NMF	6.6%	7.8%	7.2%
OGE Energy Corporation	OGE	12.9%	13.4%	12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	12.0%	12.0%	11.6%	10.3%	11.8%	11.1%
Otter Tail Corporation	OTTR	2.0%	2.7%	7.3%	9.3%	9.9%	9.7%	9.3%	10.6%	11.3%	11.1%	10.0%	11.0%	11.5%	8.3%	10.4%	10.8%	10.6%
PNM Resources, Inc.	PNM	5.2%	6.2%	6.6%	6.8%	6.5%	7.1%	7.0%	9.1%	7.9%	10.9%	8.5%	9.5%	10.0%	7.3%	8.4%	9.3%	8.9%
Southern Company	SO	12.2%	12.5%	12.8%	12.5%	12.5%	12.6%	11.0%	13.4%	12.5%	12.1%	12.0%	12.0%	12.5%	12.4%	12.3%	12.2%	12.2%
Xcel Energy Inc.	XEL	8.9%	9.9%	10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.0%	10.0%	10.5%	10.0%	10.2%	10.2%	10.2%
Mean		9.3%	9.6%	8.9%	9.1%	9.4%	9.3%	9.0%	9.7%	9.2%	9.9%	9.4%	9.8%	10.1%	9.4%	9.3%	9.8%	9.50%
Median		8.9%	8.9%	8.8%	8.7%	9.7%	9.1%	9.3%	9.8%	10.2%	10.3%	9.8%	10.0%	10.3%	9.7%	9.8%	10.0%	10.00%

Source: *Value Line Investment Survey*, Ratings & Reports (several issues - September 11, October 23, and November 13, 2020).

ECONOMIC INDICATORS

Line No	Year	Real GDP Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
			1975 - 1982 Cycle			
1	1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
2	1976	5.4%	10.8%	7.7%	4.8%	3.7%
3	1977	5.5%	5.9%	7.0%	6.8%	6.9%
4	1978	5.0%	5.7%	6.0%	9.0%	9.2%
5	1979	2.8%	4.4%	5.8%	13.3%	12.8%
6	1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
7	1981	1.8%	1.9%	7.5%	8.9%	7.1%
8	1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle			
9	1983	4.0%	3.7%	9.5%	3.8%	0.6%
10	1984	6.8%	9.3%	7.5%	3.9%	1.7%
11	1985	3.7%	1.7%	7.2%	3.8%	1.8%
12	1986	3.1%	0.9%	7.0%	1.1%	-2.3%
13	1987	2.9%	4.9%	6.2%	4.4%	2.2%
14	1988	3.8%	4.5%	5.5%	4.4%	4.0%
15	1989	3.5%	1.8%	5.3%	4.6%	4.9%
16	1990	1.8%	-0.2%	5.6%	6.1%	5.7%
17	1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle			
18	1992	3.0%	3.1%	7.5%	2.9%	1.6%
19	1993	2.7%	3.4%	6.9%	2.7%	0.2%
20	1994	4.0%	5.5%	6.1%	2.7%	1.7%
21	1995	3.7%	4.8%	5.6%	2.5%	2.3%
22	1996	4.5%	4.3%	5.4%	3.3%	2.8%
23	1997	4.5%	7.3%	4.9%	1.7%	-1.2%
24	1998	4.2%	5.8%	4.5%	1.6%	0.0%
25	1999	3.7%	4.5%	4.2%	2.7%	2.9%
26	2000	4.1%	4.0%	4.0%	3.4%	3.6%
27	2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
			2002 - 2009 Cycle			
28	2002	1.8%	0.2%	5.8%	2.4%	1.2%
29	2003	2.8%	1.2%	6.0%	1.9%	4.0%
30	2004	3.8%	2.3%	5.5%	3.3%	4.2%
31	2005	3.3%	3.2%	5.1%	3.4%	5.4%
32	2006	2.7%	2.2%	4.6%	2.5%	1.1%
33	2007	1.8%	2.5%	4.6%	4.1%	6.2%
34	2008	-0.1%	-3.5%	5.8%	0.1%	-0.9%
35	2009	-2.5%	-11.5%	9.3%	2.7%	4.3%
			Current Cycle			
36	2010	2.6%	5.5%	9.6%	1.5%	4.7%
37	2011	1.6%	3.1%	8.9%	3.0%	6.9%
38	2012	2.2%	3.0%	8.1%	1.7%	1.6%
39	2013	1.8%	2.0%	7.4%	1.5%	0.8%
40	2014	2.5%	3.1%	6.2%	0.8%	1.2%
41	2015	3.1%	-1.0%	5.3%	0.7%	-4.3%
42	2016	1.7%	-2.0%	4.9%	2.1%	-1.4%
43	2017	2.3%	2.3%	4.4%	2.1%	3.3%
44	2018	3.0%	3.9%	3.9%	1.9%	3.4%
45	2019	2.2%	0.8%	3.7%	2.3%	0.4%

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Line No	Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
1	2007					
2	1st Qtr.	0.9%	2.5%	4.5%	4.8%	6.4%
3	2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
4	3rd Qtr.	2.3%	1.8%	4.6%	1.2%	1.2%
5	4th Qtr.	2.9%	1.7%	4.8%	0.6%	6.5%
6	2008					
7	1st Qtr.	-1.8%	1.9%	4.9%	2.8%	9.6%
8	2nd Qtr.	1.3%	0.2%	5.3%	7.6%	14.0%
9	3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%	-0.4%
10	4th Qtr.	-8.9%	6.0%	6.9%	-13.2%	-28.4%
11	2009					
12	1st Qtr.	-5.3%	-11.6%	8.1%	2.4%	-0.4%
13	2nd Qtr.	-0.3%	-12.9%	9.3%	3.2%	9.2%
14	3rd Qtr.	1.4%	-9.3%	9.6%	2.0%	-0.8%
15	4th Qtr.	4.0%	-4.5%	10.0%	2.5%	8.8%
16	2010					
17	1st Qtr.	1.6%	2.7%	9.7%	0.9%	6.5%
18	2nd Qtr.	3.9%	6.5%	9.7%	-1.2%	-2.4%
19	3rd Qtr.	2.8%	6.9%	9.6%	2.8%	4.0%
20	4th Qtr.	2.8%	6.2%	9.6%	2.8%	9.2%
21	2011					
22	1st Qtr.	-1.5%	5.4%	9.0%	4.8%	9.6%
23	2nd Qtr.	2.9%	3.6%	9.0%	3.2%	3.6%
24	3rd Qtr.	0.8%	3.3%	9.1%	2.4%	6.4%
25	4th Qtr.	4.6%	4.0%	8.7%	0.4%	-1.2%
26	2012					
27	1st Qtr.	2.3%	4.5%	8.3%	3.2%	2.0%
28	2nd Qtr.	1.6%	4.7%	8.2%	0.0%	-2.8%
29	3rd Qtr.	2.5%	3.4%	8.1%	4.0%	9.6%
30	4th Qtr.	0.1%	2.8%	7.8%	0.0%	-3.6%
31	2013					
32	1st Qtr.	1.9%	2.5%	7.7%	2.0%	1.2%
33	2nd Qtr.	1.1%	2.0%	7.6%	1.2%	2.4%
34	3rd Qtr.	3.0%	2.6%	7.3%	1.6%	0.0%
35	4th Qtr.	3.8%	3.3%	7.0%	1.2%	0.3%
36	2014					
37	1st Qtr.	-1.2%	3.2%	6.6%	1.6%	0.3%
38	2nd Qtr.	4.0%	4.2%	6.2%	3.6%	0.2%
39	3rd Qtr.	5.0%	4.7%	6.1%	0.0%	0.0%
40	4th Qtr.	2.3%	4.5%	5.7%	-2.8%	-0.8%
41	2015					
42	1st Qtr.	3.2%	3.5%	5.6%	-0.2%	-2.3%
43	2nd Qtr.	2.7%	1.5%	5.4%	0.6%	1.2%
44	3rd Qtr.	1.6%	1.1%	5.2%	0.0%	-1.8%
45	4th Qtr.	0.5%	-0.8%	5.0%	0.2%	-0.9%
46	2016					
47	1st Qtr.	1.5%	-1.7%	4.9%	1.1%	-2.7%
48	2nd Qtr.	2.3%	-1.3%	4.9%	1.0%	-2.2%
49	3rd Qtr.	1.9%	-1.2%	4.9%	1.1%	-1.5%
50	4th Qtr.	1.8%	-0.1%	4.7%	1.8%	0.9%
51	2017					
52	1st Qtr.	1.8%	0.6%	4.7%	2.5%	3.7%
53	2nd Qtr.	3.0%	2.2%	4.3%	1.9%	3.1%
54	3rd Qtr.	2.8%	1.6%	4.3%	1.9%	2.9%
55	4th Qtr.	2.3%	3.5%	4.1%	2.1%	3.6%
56	2018					
57	1st Qtr.	3.8%	3.5%	4.1%	1.7%	3.2%
58	2nd Qtr.	2.7%	3.3%	3.9%	2.3%	3.9%
59	3rd Qtr.	2.1%	4.9%	3.8%	1.3%	3.9%
60	4th Qtr.	1.3%	3.9%	3.8%	1.0%	2.5%
61	2019					
62	1st Qtr.	2.9%	2.9%	3.9%	0.2%	0.8%
63	2nd Qtr.	1.5%	1.1%	3.6%	0.2%	0.8%
64	3rd Qtr.	2.6%	0.2%	3.6%	0.2%	-0.1%
65	4th Qtr.	2.4%	-0.7%	3.5%	0.2%	0.2%
66	2020					
67	1st Qtr.	-5.0%	-1.9%	3.8%	-0.1%	0.2%
68	2nd Qtr.	-31.4%	-14.4%	13.0%	-0.1%	-3.7%
69	3rd Qtr.	33.1%		8.8%		
70	4th Qtr.					

*GDP=Gross Domestic Product
Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Line No	Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1	1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
2	1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
3	1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
4	1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
5	1979	12.67%	10.04%	9.43%	9.86%	10.22%	10.49%	10.96%
6	1980	15.27%	11.51%	11.43%	12.30%	13.00%	13.34%	13.95%
7	1981	18.89%	14.03%	13.92%	14.64%	15.30%	15.95%	16.60%
8	1982	14.86%	10.69%	13.01%	14.22%	14.79%	15.86%	16.45%
9	1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
10	1984	12.04%	9.58%	12.46%	12.72%	13.66%	14.03%	14.53%
11	1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
12	1986	8.33%	5.98%	7.67%	8.92%	9.30%	9.58%	10.00%
13	1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
14	1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
15	1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
16	1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
17	1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
18	1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
19	1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
20	1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
21	1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
22	1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
23	1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
24	1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
25	1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
26	2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
27	2001	6.91%	3.44%	5.02%	7.47%	7.59%	7.78%	8.02%
28	2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
29	2003	4.12%	1.01%	4.01%		6.40%	6.58%	6.84%
30	2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
31	2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
32	2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
33	2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
34	2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
35	2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
36	2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%
37	2011	3.25%	0.06%	2.78%		4.78%	5.04%	5.57%
38	2012	3.25%	0.09%	1.80%		3.83%	4.13%	4.86%
39	2013	3.25%	0.06%	2.35%		4.24%	4.47%	4.98%
40	2014	3.25%	0.03%	2.54%		4.19%	4.28%	4.80%
41	2015	3.27%	0.06%	2.14%		4.00%	4.12%	5.03%
42	2016	3.51%	0.33%	1.84%		3.73%	3.93%	4.68%
43	2017	4.13%	0.94%	2.33%		3.82%	4.00%	4.38%
44	2018	4.96%	1.94%	2.91%		4.09%	4.25%	4.67%
45	2019	5.25%	2.09%	2.14%		3.61%	3.77%	4.19%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Mergent Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Moody's Rated Utility Bonds Aa	Moody's Rated Utility Bonds A	Moody's Rated Utility Bonds Baa
1	2009						
2	Jan	3.25%	0.12%	2.52%	6.01%	6.39%	7.90%
3	Feb	3.25%	0.31%	2.87%	6.11%	6.30%	7.74%
4	Mar	3.25%	0.25%	2.82%	6.14%	6.42%	8.00%
5	Apr	3.25%	0.17%	2.93%	6.20%	6.48%	8.03%
6	May	3.25%	0.15%	3.29%	6.23%	6.49%	7.76%
7	June	3.25%	0.17%	3.72%	6.13%	6.20%	7.30%
8	July	3.25%	0.19%	3.56%	5.63%	5.97%	6.87%
9	Aug	3.25%	0.18%	3.59%	5.33%	5.71%	6.36%
10	Sept	3.25%	0.13%	3.40%	5.15%	5.53%	6.12%
11	Oct	3.25%	0.08%	3.39%	5.23%	5.55%	6.14%
12	Nov	3.25%	0.05%	3.40%	5.33%	5.64%	6.18%
13	Dec	3.25%	0.07%	3.59%	5.52%	5.79%	6.26%
14	2010						
15	Jan	3.25%	0.06%	3.73%	5.55%	5.77%	6.16%
16	Feb	3.25%	0.10%	3.69%	5.69%	5.87%	6.25%
17	Mar	3.25%	0.15%	3.73%	5.64%	5.84%	6.22%
18	Apr	3.25%	0.15%	3.85%	5.62%	5.81%	6.19%
19	May	3.25%	0.16%	3.42%	5.29%	5.50%	5.97%
20	June	3.25%	0.12%	3.20%	5.22%	5.46%	6.18%
21	July	3.25%	0.16%	3.01%	4.99%	5.26%	5.98%
22	Aug	3.25%	0.15%	2.70%	4.75%	5.01%	5.55%
23	Sept	3.25%	0.15%	2.65%	4.74%	5.01%	5.53%
24	Oct	3.25%	0.13%	2.54%	4.89%	5.10%	5.62%
25	Nov	3.25%	0.13%	2.76%	5.12%	5.37%	5.85%
26	Dec	3.25%	0.15%	3.29%	5.32%	5.56%	6.04%
27	2011						
28	Jan	3.25%	0.15%	3.39%	5.29%	5.57%	6.06%
29	Feb	3.25%	0.14%	3.58%	5.42%	5.68%	6.10%
30	Mar	3.25%	0.11%	3.41%	5.33%	5.56%	5.97%
31	Apr	3.25%	0.06%	3.46%	5.32%	5.55%	5.98%
32	May	3.25%	0.04%	3.17%	5.08%	5.32%	5.74%
33	June	3.25%	0.04%	3.00%	5.04%	5.26%	5.67%
34	July	3.25%	0.03%	3.00%	5.05%	5.27%	5.70%
35	Aug	3.25%	0.05%	2.30%	4.44%	4.69%	5.22%
36	Sept	3.25%	0.02%	1.98%	4.24%	4.48%	5.11%
37	Oct	3.25%	0.02%	2.15%	4.21%	4.52%	5.24%
38	Nov	3.25%	0.01%	2.01%	3.92%	4.25%	4.93%
39	Dec	3.25%	0.02%	1.98%	4.00%	4.33%	5.07%
40	2012						
41	Jan	3.25%	0.02%	1.97%	4.03%	4.34%	5.06%
42	Feb	3.25%	0.08%	1.97%	4.02%	4.36%	5.02%
43	Mar	3.25%	0.09%	2.17%	4.16%	4.48%	5.13%
44	Apr	3.25%	0.08%	2.05%	4.10%	4.40%	5.11%
45	May	3.25%	0.09%	1.80%	3.92%	4.20%	4.97%
46	June	3.25%	0.09%	1.62%	3.79%	4.08%	4.91%
47	July	3.25%	0.10%	1.53%	3.58%	3.93%	4.85%
48	Aug	3.25%	0.11%	1.68%	3.65%	4.00%	4.88%
49	Sept	3.25%	0.10%	1.72%	3.69%	4.02%	4.81%
50	Oct	3.25%	0.10%	1.75%	3.68%	3.91%	4.54%
51	Nov	3.25%	0.11%	1.65%	3.60%	3.84%	4.42%
52	Dec	3.25%	0.08%	1.72%	3.75%	4.00%	4.56%

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Moody's Rated Utility Bonds Aa	Moody's Rated Utility Bonds A	Moody's Rated Utility Bonds Baa
1	2013						
2	Jan	3.25%	0.07%	1.91%	3.90%	4.15%	4.66%
3	Feb	3.25%	0.10%	1.98%	3.95%	4.18%	4.74%
4	Mar	3.25%	0.09%	1.96%	3.90%	4.15%	4.66%
5	Apr	3.25%	0.06%	1.76%	3.74%	4.00%	4.49%
6	May	3.25%	0.05%	1.93%	3.91%	4.17%	4.65%
7	June	3.25%	0.05%	2.30%	4.27%	4.53%	5.08%
8	July	3.25%	0.04%	2.58%	4.44%	4.68%	5.21%
9	Aug	3.25%	0.04%	2.74%	4.53%	4.73%	5.28%
10	Sept	3.25%	0.02%	2.81%	4.58%	4.80%	5.31%
11	Oct	3.25%	0.06%	2.62%	4.48%	4.70%	5.17%
12	Nov	3.25%	0.07%	2.72%	4.56%	4.77%	5.24%
13	Dec	3.25%	0.07%	2.90%	4.59%	4.81%	5.25%
14	2014						
15	Jan	3.25%	0.05%	2.86%	4.44%	4.63%	5.09%
16	Feb	3.25%	0.06%	2.71%	4.38%	4.53%	5.01%
17	Mar	3.25%	0.05%	2.72%	4.40%	4.51%	5.00%
18	Apr	3.25%	0.04%	2.71%	4.30%	4.41%	4.85%
19	May	3.25%	0.03%	2.56%	4.16%	4.26%	4.69%
20	June	3.25%	0.03%	2.60%	4.23%	4.29%	4.73%
21	July	3.25%	0.03%	2.54%	4.16%	4.23%	4.66%
22	Aug	3.25%	0.03%	2.42%	4.07%	4.13%	4.65%
23	Sept	3.25%	0.02%	2.53%	4.18%	4.24%	4.79%
24	Oct	3.25%	0.02%	2.30%	3.96%	4.06%	4.67%
25	Nov	3.25%	0.02%	2.33%	4.03%	4.09%	4.75%
26	Dec	3.25%	0.04%	2.21%	3.90%	3.95%	4.70%
27	2015						
28	Jan	3.25%	0.03%	1.88%	3.52%	3.58%	4.39%
29	Feb	3.25%	0.02%	1.98%	3.62%	3.67%	4.44%
30	Mar	3.25%	0.03%	2.04%	3.67%	3.74%	4.51%
31	Apr	3.25%	0.02%	1.94%	3.63%	3.75%	4.51%
32	May	3.25%	0.02%	2.20%	4.05%	4.17%	4.91%
33	June	3.25%	0.02%	2.36%	4.29%	4.39%	5.13%
34	July	3.25%	0.03%	2.32%	4.27%	4.40%	5.22%
35	Aug	3.25%	0.07%	2.17%	4.13%	4.25%	5.23%
36	Sept	3.25%	0.02%	2.17%	4.25%	4.39%	5.42%
37	Oct	3.25%	0.02%	2.07%	4.13%	4.29%	5.47%
38	Nov	3.25%	0.13%	2.26%	4.22%	4.40%	5.57%
39	Dec	3.50%	0.23%	2.24%	4.18%	4.35%	5.55%
40	2016						
41	Jan	3.50%	0.26%	2.09%	4.09%	4.27%	5.49%
42	Feb	3.50%	0.31%	1.78%	3.94%	4.11%	5.28%
43	Mar	3.50%	0.30%	1.89%	3.93%	4.16%	5.12%
44	Apr	3.50%	0.23%	1.81%	3.74%	4.00%	4.75%
45	May	3.50%	0.27%	1.81%	3.65%	3.93%	4.60%
46	Jun	3.50%	0.27%	1.64%	3.56%	3.78%	4.47%
47	Jul	3.50%	0.30%	1.50%	3.36%	3.57%	4.16%
48	Aug	3.50%	0.30%	1.56%	3.39%	3.59%	4.20%
49	Sep	3.50%	0.29%	1.63%	3.47%	3.66%	4.27%
50	Oct	3.50%	0.33%	1.76%	3.59%	3.77%	4.34%
51	Nov	3.50%	0.45%	2.14%	3.91%	4.08%	4.64%
52	Dec	3.75%	0.51%	2.49%	4.11%	4.27%	4.79%

Line No		Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Moody's Rated Utility Bonds Aa	Moody's Rated Utility Bonds A	Moody's Rated Utility Bonds Baa
1	2017						
2	Jan	3.75%	0.52%	2.43%	3.96%	4.14%	4.62%
3	Feb	3.75%	0.53%	2.42%	3.99%	4.18%	4.58%
4	Mar	4.00%	0.72%	2.48%	4.04%	4.23%	4.62%
5	Apr	4.00%	0.81%	2.30%	3.93%	4.12%	4.51%
6	May	4.00%	0.89%	2.30%	3.94%	4.12%	4.50%
7	Jun	4.25%	0.99%	2.19%	3.77%	3.94%	4.32%
8	Jul	4.25%	1.08%	2.32%	3.82%	3.99%	4.36%
9	Aug	4.25%	1.03%	2.21%	3.67%	3.86%	4.23%
10	Sep	4.25%	1.04%	2.20%	3.70%	3.87%	4.24%
11	Oct	4.25%	1.08%	2.36%	3.74%	3.91%	4.26%
12	Nov	4.25%	1.25%	2.35%	3.65%	3.83%	4.16%
13	Dec	4.50%	1.34%	2.40%	3.62%	3.79%	4.14%
14	2018						
15	Jan	4.50%	1.43%	2.58%	3.69%	3.86%	4.18%
16	Feb	4.50%	1.59%	2.86%	3.94%	4.09%	4.42%
17	Mar	4.75%	1.73%	2.84%	3.97%	4.13%	4.52%
18	Apr	4.75%	1.79%	2.87%	3.99%	4.17%	4.58%
19	May	4.75%	1.90%	2.98%	4.10%	4.28%	4.71%
20	Jun	5.00%	1.94%	2.91%	4.11%	4.27%	4.71%
21	Jul	5.00%	1.99%	2.89%	4.10%	4.27%	4.67%
22	Aug	5.00%	2.07%	2.89%	4.08%	4.26%	4.64%
23	Sep	5.25%	2.17%	3.00%	4.18%	4.32%	4.74%
24	Oct	5.25%	2.29%	3.15%	4.31%	4.45%	4.91%
25	Nov	5.25%	2.37%	3.12%	4.40%	4.52%	5.03%
26	Dec	5.50%	2.41%	2.83%	4.24%	4.37%	4.92%
27	2019						
28	Jan	5.50%	2.42%	2.71%	4.18%	4.35%	4.91%
29	Feb	5.50%	2.44%	2.68%	4.05%	4.25%	4.76%
30	Mar	5.50%	2.45%	2.57%	3.98%	4.16%	4.65%
31	Apr	5.50%	2.43%	2.53%	3.91%	4.08%	4.55%
32	May	5.50%	2.40%	2.40%	3.84%	3.98%	4.47%
33	Jun	5.50%	2.22%	2.07%	3.65%	3.82%	4.31%
34	Jul	5.50%	2.15%	2.06%	3.53%	3.69%	4.13%
35	Aug	5.25%	1.99%	1.63%	3.17%	3.29%	3.63%
36	Sep	5.00%	1.93%	1.70%	3.24%	3.37%	3.71%
37	Oct	4.75%	1.55%	1.71%	3.24%	3.39%	3.72%
38	Nov	4.75%	1.54%	1.81%	3.25%	3.43%	3.76%
39	Dec	4.75%	1.57%	1.86%	3.22%	3.40%	3.73%
40	2020						
41	Jan	4.75%	1.55%	1.78%	3.12%	3.29%	3.60%
42	Feb	4.75%	1.54%	1.50%	2.96%	3.11%	3.42%
43	Mar	3.25%	0.30%	0.87%	3.30%	3.50%	3.96%
44	Apr	3.25%	0.14%	0.66%	2.93%	3.19%	3.82%
45	May	3.25%	0.13%	0.67%	2.89%	3.14%	3.63%
46	Jun	3.25%	0.16%	0.73%	2.80%	3.07%	3.44%
47	Jul	3.25%	0.13%	0.62%	2.46%	2.74%	3.09%
48	Aug	3.25%	0.10%	0.65%	2.49%	2.73%	3.06%
49	Sep	3.25%	0.11%	0.68%	2.62%	2.84%	3.17%
50	Oct	3.25%	0.10%	0.79%	2.72%	2.95%	3.27%
51	Nov	3.25%	0.09%	0.87%	2.63%	2.85%	3.17%
52	Dec						

[1] Note: Moody's has not published Aaa utility bond yields since 2001.
Sources: Council of Economic Advisors, Economic Indicators; Mergent Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Line No	Year	S&P Composite	NASDAQ Composite	DJIA	S&P Dividend/Price Ratio	S&P Earnings/Price Ratio
1	1975			802.49	4.31%	9.15%
2	1976			974.92	3.77%	8.90%
3	1977			894.63	4.62%	10.79%
4	1978			820.23	5.28%	12.03%
5	1979			844.40	5.47%	13.46%
6	1980			891.41	5.26%	12.66%
7	1981			932.92	5.20%	11.96%
8	1982			884.36	5.81%	11.60%
9	1983			1,190.34	4.40%	8.03%
10	1984			1,178.48	4.64%	10.02%
11	1985			1,328.23	4.25%	8.12%
12	1986			1,792.76	3.49%	6.09%
13	1987			2,275.99	3.08%	5.48%
14	1988			2,060.82	3.64%	8.01%
15	1989	322.84		2,508.91	3.45%	7.41%
16	1990	334.59		2,678.94	3.61%	6.47%
17	1991	376.18	491.69	2,929.33	3.24%	4.79%
18	1992	415.74	599.26	3,284.29	2.99%	4.22%
19	1993	451.21	715.16	3,522.06	2.78%	4.46%
20	1994	460.42	751.65	3,793.77	2.82%	5.83%
21	1995	541.72	925.19	4,493.76	2.56%	6.09%
22	1996	670.50	1,164.96	5,742.89	2.19%	5.24%
23	1997	873.43	1,469.49	7,441.15	1.77%	4.57%
24	1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
25	1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
26	2000	1,427.22	2,783.67	10,734.90	1.15%	3.63%
27	2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
28	2002	993.94	1,539.73	9,226.43	1.61%	2.92%
29	2003	965.23	1,647.17	8,993.59	1.77%	3.84%
30	2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
31	2005	1,207.06	2,099.03	10,547.67	1.83%	5.36%
32	2006	1,310.67	2,265.17	11,408.67	1.87%	5.78%
33	2007	1,476.66	2,577.12	13,169.98	1.86%	5.29%
34	2008	1,220.89	2,162.46	11,252.61	2.37%	3.54%
35	2009	946.73	1,841.03	8,876.15	2.40%	1.86%
36	2010	1,139.31	2,347.70	10,662.80	1.97%	6.04%
37	2011	1,268.89	2,680.42	11,966.36	1.99%	6.77%
38	2012	1,379.56	2,965.77	12,967.08	2.09%	6.20%
39	2013	1,642.51	3,537.69	14,999.67	2.08%	5.57%
40	2014	1,930.67	4,374.31	16,773.99	1.94%	5.25%
41	2015	2,061.20	4,943.49	17,590.61	2.05%	4.59%
42	2016	2,092.39	4,982.49	17,908.08	2.18%	4.17%
43	2017	2,448.22	6,231.28	21,741.91	1.97%	4.22%
44	2018	2,744.68	7,419.27	25,045.75	1.90%	4.67%
45	2019	2,912.50	7,936.85	26,378.41	1.93%	4.53%

Source: Council of Economic Advisors, Economic Indicators, various issues.
https://www.gpo.gov/fdsys/browse/collection.action?collectionCode=ECONI

STOCK PRICE INDICATORS

Line No		S&P Composite	NASDAQ Composite	DJIA	S&P Dividends/Price Ratio	S&P Earnings/Price Ratio
1	**2007**					
2	1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
3	2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
4	3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
5	4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
6	**2008**					
7	1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
8	2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
9	3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
10	4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
11	**2009**					
12	1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
13	2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
14	3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
15	4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
16	**2010**					
17	1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
18	2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
19	3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
20	4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
21	**2011**					
22	1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
23	2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
24	3rd Qtr.	1,237.12	2,613.11	11,671.47	2.15%	7.69%
25	4th Qtr.	1,225.65	2,600.91	11,798.65	2.25%	6.91%
26	**2012**					
27	1st Qtr.	1,347.44	2,902.90	12,839.80	2.12%	6.29%
28	2nd Qtr.	1,350.39	2,928.62	12,765.58	2.30%	6.45%
29	3rd Qtr.	1,402.21	3,029.86	13,118.72	2.27%	6.00%
30	4th Qtr.	1,418.21	3,001.69	13,142.91	2.28%	6.07%
31	**2013**					
32	1st Qtr.	1,514.41	3,177.10	14,000.30	2.21%	5.59%
33	2nd Qtr.	1,609.77	3,369.49	14,961.28	2.15%	5.66%
34	3rd Qtr.	1,675.31	3,643.63	15,255.25	2.14%	5.65%
35	4th Qtr.	1,770.45	3,960.54	15,751.96	2.06%	5.42%
36	**2014**					
37	1st Qtr.	1,834.30	4,210.05	16,170.26	2.04%	5.39%
38	2nd Qtr.	1,900.37	4,195.81	16,603.50	2.06%	5.26%
39	3rd Qtr.	1,975.95	4,483.51	16,953.85	2.02%	5.38%
40	4th Qtr.	2012.04	4607.88	17368.36	2.03%	4.97%
41	**2015**					
42	1st Qtr.	2063.46	4821.99	17806.47	2.02%	4.80%
43	2nd Qtr.	2102.03	5017.47	18007.48	2.05%	4.60%
44	3rd Qtr.	2,026.14	4,921.81	17,065.52	2.16%	4.72%
45	4th Qtr.	2,053.17	5,000.70	17,482.97	2.16%	4.23%
46	**2016**					
47	1st Qtr.	1,948.32	4,609.47	16,635.76	2.31%	4.20%
48	2nd Qtr.	2,074.99	4,845.55	17,763.85	2.19%	4.14%
49	3rd Qtr.	2,161.36	5,165.06	18,367.92	2.13%	4.11%
50	4th Qtr.	2,184.88	5,309.89	18,864.77	2.13%	4.22%
51	**2017**					
52	1st Qtr.	2,323.95	5,730.36	20,385.12	2.05%	4.24%
53	2nd Qtr.	2,396.22	6,087.11	20,979.77	2.02%	4.29%
54	3rd Qtr.	2,467.72	6,344.72	21,889.58		4.25%
55	4th Qtr.	2,604.98	6,762.93	23,713.18		4.11%
56	**2018**					
57	1st Qtr.	2,732.58	7,250.93	25,122.58	1.88%	4.37%
58	2nd Qtr.	2,703.16	7,356.20	24,555.62	1.92%	4.51%
59	3rd Qtr.	2,850.99	7,877.47	25,613.63	1.83%	4.47%
60	4th Qtr.	2,692.00	7,192.48	24,891.19	1.98%	5.28%
61	**2019**					
62	1st Qtr.	2,722.08	7,346.37	25,161.98	2.00%	4.74%
63	2nd Qtr.	2,882.89	7,874.48	26,102.16	1.93%	4.60%
64	3rd Qtr.	2,958.59	8,068.08	26,682.54	1.92%	4.46%
65	4th Qtr.	3,086.44	8,458.48	27,566.95	1.88%	4.32%
66	**2020**					
67	1st Qtr.	3,069.30	8,808.14	26,679.05	1.80%	4.50%
68	2nd Qtr.	2,928.75	9,079.35	24,542.40		3.21%
69	3rd Qtr.	3,321.62	10,933.61	27,313.53		
70	4th Qtr.					

Source: Council of Economic Advisors, Economic Indicators, various issues.
https://www.gpo.gov/fdsys/browse/collection.action?collectionCode=ECONI
https://ycharts.com/indicators/sp_500_dividend_yield

PROXY GROUP COMMON EQUITY RATIOS

			Historical										10-Year	5-Year	Projected			5-Year	Combined
	Company	Ticker	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average 2010-2019	Average 2015-2019	2020	2021	2023-'25	Average 2020-2024	5-Yr Historical & Projected Avg.
1	Allete, Inc.	ALE	55.8%	55.7%	56.3%	55.4%	55.8%	53.7%	58.0%	59.0%	60.1%	61.4%	57.1%	58.4%	59.0%	60.0%	59.0%	59.3%	58.9%
2	Ameren Corporation	AEE	50.9%	53.7%	49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	50.6%	49.3%	45.5%	47.0%	49.0%	47.2%	48.3%
3	American Electric Power Company	AEP	46.7%	49.3%	49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	48.5%	47.9%	44.0%	46.0%	48.0%	46.0%	46.9%
4	DTE Energy Company	DTE	48.7%	49.4%	51.2%	52.3%	50.0%	49.8%	44.4%	43.8%	45.8%	42.3%	47.8%	45.2%	40.0%	40.0%	41.5%	40.5%	42.9%
5	Duke Energy Corporation	DUK	55.7%	54.9%	52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	50.3%	47.0%	45.0%	44.5%	44.5%	44.7%	45.8%
6	Exelon Corporation	EXC	52.9%	54.0%	53.5%	55.2%	52.8%	51.3%	44.5%	47.8%	47.2%	50.4%	51.0%	48.2%	48.0%	49.5%	49.5%	49.0%	48.6%
7	Evergy, Inc.	EVRG									60.0%	49.4%	N/A	54.7%	48.5%	47.5%	46.5%	47.5%	51.1%
8	OGE Energy Corporation	OGE	49.2%	48.4%	49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	54.5%	57.5%	51.0%	52.0%	51.0%	51.3%	54.4%
9	Otter Tail Corporation	OTTR	58.4%	54.0%	54.4%	57.9%	53.5%	57.6%	57.0%	58.7%	55.3%	53.1%	56.0%	56.3%	58.0%	55.0%	53.0%	55.3%	55.8%
10	PNM Resources, Inc.	PNM	49.2%	48.1%	48.7%	49.7%	51.9%	45.5%	44.0%	43.6%	38.6%	39.9%	45.9%	42.3%	48.0%	44.0%	47.5%	46.5%	44.4%
11	Southern Company	SO	45.7%	47.1%	47.3%	45.8%	47.3%	44.0%	35.7%	35.0%	37.6%	39.5%	42.5%	38.4%	37.5%	37.0%	38.5%	37.7%	38.0%
12	Excel Energy Inc.	XEL	46.3%	48.9%	46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	45.6%	44.1%	43.0%	43.0%	43.0%	43.0%	43.6%
13	Average		50.9%	51.2%	50.8%	52.2%	51.6%	50.4%	48.8%	48.6%	49.0%	47.6%	50.0%	49.1%	47.3%	47.1%	47.6%	47.3%	48.2%

Source: *Value Line Investment Survey*, Ratings & Reports (several issues - August 14, September 11, and October 23, 2020).